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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In The Matter Of the Application Of HAWAII ELECTRIC LIGHT COMPANY, INC. For Approval of Rate Increases and Revised Rate Schedules and Rules.	DOCKET NO. 05-0315

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OPENING BRIEF
OF
HAWAII ELECTRIC LIGHT COMPANY, INC.

AND

CERTIFICATE OF SERVICE

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TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

Page

TABLE OF AUTHORITIES

HAWAII COMMISSION DECISIONS

COURT DECISIONS

OTHER RULINGS

FEDERAL STATUTES

HAWAII REVISED STATUTES

HAWAII ADMINISTRATIVE RULES

OTHER AUTHORITIES

1772103.1

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OPENING BRIEF OF HAWAII ELECTRIC LIGHT COMPANY, INC.

This Opening Brief is respectfully submitted on behalf of HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO" or the "Company").

I. INTRODUCTION

HELCO'S REQUESTED RATE RELIEF

HELCO is seeking timely and adequate rate relief for a number of reasons. First, HELCO has made investments in plant and implemented activities not only to keep up with growth on the Big Island but also to improve and maintain service reliability. Second, HELCO needs to improve its returns to maintain its integrity in the financial markets and assure reasonable costs of capital for its ratepayers in the future. Third, HELCO needs to restructure its rates to promote efficient energy use and reward customers who use energy wisely. Based on settlement agreements with the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate"), HELCO requests a revenue increase of $24,564,500 or 7.58% over revenues of $324,073,100 at present rates for a normalized 2006 test year. The Company's normalized test year revenue requirement of $348,637,600 is based on an 8.33% return on average rate base and a 10.7% return on common equity.

A. BACKGROUND

1. Application

On December 13, 2005, HELCO filed a Notice of Intent in Docket No. 05-0315 (the "Rate Case Docket") with the Commission in which it stated that it planned to request rate relief based on a 2006 calendar year test period, and a Motion for Approval of Test Period Waiver to allow HELCO to use a 2006 calendar year test period for the general rate increase application. HELCO received Commission approval in Order No. 22212 (issued January 9, 2006) to use a calendar year 2006 test period (for a general rate increase application it would file on or after March 15, 2006 but before June 30, 2006) rather than a split test year of July 1, 2006 through June 30, 2007 as required by Section 6-61-87(4) of the Hawaii Administrative Rules.

On May 5, 2006, HELCO filed an Application requesting approval of a general rate increase and revised rate schedules and rules. The amount of the increase in base rate revenues requested was $29,931,100, or 9.24%, over revenues at present rates. The requested increase was based on estimated total revenue requirements of $354,019,700 for the normalized 2006 test year (based on February 1, 2006 fuel oil prices and an 8.65% rate of return on HELCO's average rate base).

Present rates are rates currently in effect at the time of the Application, excluding revenues HELCO currently collects through the Demand-Side Management ("DSM") component of the Integrated Resource Planning ("IRP") surcharge ("DSM surcharge"). HELCO excluded DSM revenues and costs from the 2006 test year because Docket No. 05-0069 (Energy Efficiency proceeding) was in progress at the time HELCO's direct testimonies, exhibits, workpapers and Application were filed and was going to address a number of policy issues on DSM programs in the state, including on the island of Hawaii ("Hawaii"). The issues included what the cost recovery mechanism for DSM programs should be (e.g., whether the costs should be recovered through base rates or a separate surcharge). Because of this, for purposes of HELCO's Application, direct testimonies, exhibits and workpapers, HELCO excluded from its 2006 test year revenue requirements the DSM costs currently recovered through the DSM surcharge. Because the DSM costs recovered through the surcharge were excluded, the DSM surcharge revenues were also removed from the case.

The Application and written direct testimonies discussed the principal factors driving the need for HELCO to file this rate case. Without further rate relief in this proceeding, it was estimated that, at present rates (based on February 1, 2006 fuel prices), HELCO's rate of return on its average rate base would be approximately 4.10% for the normalized 2006 test year, as compared to the 9.14% authorized by the Commission in Docket No. 99-0207 for test year 2000.

HELCO's direct testimonies discussed how HELCO has made investments in plant and implemented activities to not only keep up with growth on Hawaii but also to improve and maintain service reliability. For example, HELCO has worked to improve the reliability of its own generating fleet. These activities include placing in operation in 2004, CT-4 and CT-5 combustion turbine generators at the Keahole generating station which have produced numerous system benefits. In addition, HELCO implemented a Generation Asset Management program to improve the reliability of HELCO's older generating units, and a number of measures to improve and maintain the reliability of its transmission and distribution system.

HELCO's direct testimonies discussed the reasons that HELCO needs to restructure its rates to promote efficient energy use and reward customers who use energy wisely. Given the necessity of electricity to Hawaii's customers, HELCO seeks to mitigate the impact of a rate increase on those who conserve energy or have limited incomes. While the majority of

HELCO's residential customers use electricity at sensible levels, a small percentage of customers use large amounts of energy that disproportionately drive the need for additional capacity in HELCO's systems. To address this, HELCO proposed the following:

1. Implement an inclining, three-tiered block rate design for residential (Schedule R) customers.

2. Modify the minimum charge for residential customers.

3. Exempt residential customers receiving bill credits under the Low Income Home Energy Assistance Program ("LIHEAP") from the two most costly tiers of the three-tiered inclining block rate design and limit their minimum monthly charge to $20.[1]

4. Implement a Renewable Energy and Energy Efficiency Program for Affordable Homes ("REEEPAH"), which will provide lower income residential customers with opportunities and incentives to use renewable energy.

In addition, HELCO proposed new optional time-of-use ("TOU") rates for residential, small commercial, commercial and large power customers, which will provide incentives through rate differentials for customers to use energy in off-peak periods and refrain from consumption during peak periods.

In direct testimony supporting its application, HELCO further explained that in timing its applications for rate increases, it has tried to strike a reasonable balance between maintaining its financial integrity (i.e., the financial health of the Company – having sufficient funds to fulfill the electrical needs of its customers and prudently plan for future needs, while at the same time providing a reasonable rate of return for its shareholders and ability to attract new capital on reasonable terms) and the impact of a rate increase on its customers. It had been over six years

[1] In order to address concerns from the LIHEAP administrator over the disclosure of personal information, HELCO is now planning to have the exemption available to LIHEAP customers that apply for the exemption.

since HELCO submitted a request for a general rate increase. HELCO explained that its present rates are not sufficient for it to maintain its financial integrity. If HELCO does not maintain its financial integrity, investors will invest their money elsewhere which will have negative implications for HELCO's customers because it will reduce the demand for HELCO's securities and increase HELCO's cost of capital. In adverse market conditions, it may be difficult to attract capital.

HELCO requested that the general rate increase and the revisions to its rate schedules and rules be granted in two steps: First, an Interim Increase equal to an increase in rates to which the Commission believed HELCO was "probably entitled" based on the evidentiary record before it, in accordance with Section 269-16(d) of the Hawaii Revised Statues ("H.R.S."), and a Final Increase (i.e., a General Rate Increase) when the Commission issues its final decision and order to provide for the amount of the total requested revenue increase not included in the Interim Rate Increase.

HELCO filed its completed Application, and direct testimonies, exhibits, and workpapers, with the Commission on May 5, 2006. In accordance with the Commission's Rules of Practice and Procedure, Title 6, Chapter 61, of the Hawaii Administrative Rules, the Company served copies on the Consumer Advocate, and the Mayor of the County of Hawaii. The Application, together with the written testimonies, exhibits, and workpapers, satisfied the completed application requirements of the Commission's Rules of Practice and Procedure.

2. **Direct Written Testimonies**

HELCO's May 5, 2006 Application was accompanied by a considerable amount of supporting material, including, the direct written testimonies of 21 witnesses, and accompanying exhibits and workpapers.

Generally, the revenue requirements included in the direct testimonies were based on HELCO's June 2005 sales forecast, its 2006 Operating and Maintenance ("O&M") Expense Budget (which was initially developed in the 2005 budgeting process, which was reviewed and revised in August 2005 to January 2006, estimated increases in rate base based on the expected completion dates for capital projects, a rate of return on rate base of 8.65%, and normalization adjustments necessary to better reflect operating conditions during the period when the rates as a result of this case will be in effect. HELCO T-1 at 27. The Company fixed most of the inputs to its revenue requirements calculation in April 2006. HELCO T-1 at 28.

Three forms of adjustments were made to the 2006 O&M Expense Budget to determine the test year estimates: (1) budget adjustments, (2) issue simplification adjustments, and (3) normalization adjustments. HELCO T-1 at 27.

Budget adjustments were made to the 2006 operating budget for rate case purposes. Budget adjustments are made primarily (1) to correct for errors, (2) to update the budget for better estimates, (3) to reclassify certain costs from one account to another account or from a capital account to an O&M account, and (4) to adjust labor costs for personnel budgeted to be present at the beginning of the test year, but hired or anticipated to be hired after January 1, 2006, unless offset by contract labor or additional overtime beyond that which is in the test year estimates. Many of the budget adjustments were necessary to reclassify certain budgeted information from one account to another account. These budget adjustments resulted from the budgeted information being distributed to the wrong account.

Issue simplification adjustments were made by deleting certain costs from the test year results of operations, which were denied and/or contested in prior rate cases, in order to simplify and limit the contested issues in this case.[2] HELCO's position continues to be that these are appropriate costs of doing business that HELCO will actually incur, and that must be included in rates if HELCO is to be afforded a full opportunity to earn a fair return. Therefore, HELCO has not waived its right to seek recovery of these costs in future rate cases. HELCO T-1 at 27-28; HELCO T-9 at 81-82. Rate case adjustments also include adjustments made to reflect consistent assumptions in the rate case. See HELCO T-9 at 82.

Normalization adjustments are ratemaking rather than budget adjustments. Normalization adjustments are intended to make the test year results of operation more representative of a normal, on-going level of operations, or of the operating conditions that are expected to be in effect during the period that the rates set in this docket will be in effect. For example, it may be appropriate to amortize an unusual, non-recurring expense over a period of several years for ratemaking purposes if rates are not adjusted on an annual basis. HELCO T-9 at 82.

In past proceedings, HELCO made several commitments to the Consumer Advocate in order to facilitate future ratemaking proceedings including commitments to provide in future rate case direct testimonies: (1) a variance analysis on O&M differences by activity from prior period of amount of $45,000 or more, and +/- 10%, and (2) a listing of O&M expenses that were prepared using a general inflation factor. Each O&M witness provided a variance analysis of the difference between actual 2005 and budget 2006 expenses by activity and code block. A listing of O&M expenses derived with the use of a general inflation factor was presented in HELCO T-9. HELCO T-1 at 30.

[2] Examples of items for which HELCO is not seeking cost recovery in this proceeding are non-qualified pension expenses, incentive compensation for employees and executives, Hawaiian Electric Industries Retirement System's ("HEIRS") 401(k) administration expense, and the expenses related to the annual service awards and Executive Life Insurance. HELCO T-1 at 29.

To simplify its presentation, HELCO provided all of its Rate Case Reports for O&M expenses in one place (rather than in separate parts divided among each witness' exhibits and workpapers), as HELCO-WP-101. In addition, the Rate Case Reports were presented in nine different formats to provide additional detail with which to evaluate the reasonableness of HELCO's O&M expenses. HELCO T-1 at 29. By letter dated May 9, 2006, HELCO transmitted to the Consumer Advocate actual 2000 through 2005 recorded and 2006 budgeted O&M expenses on a CD in a format similar to that requested by the Consumer Advocate in prior cases.

3. The Public Hearings

On June 26 and 27, 2006, the Commission held public hearings in Hilo and Kona, respectively, to gather public comments on this docket. The Commission published notice of the public hearings on June 4, 11, 18 and 25, 2006. HELCO published its notice of the public hearings on June 14, 2006. The Affidavit of Publication of HELCO's Notice of Public Hearing was filed on June 29, 2006.

4. The Consumer Advocate and KDC

The Consumer Advocate was made a party to the rate case pursuant to §269-51 of the H.R.S.

On July 6, 2006, the Keahole Defense Coalition, Inc. ("KDC") filed a motion to participate. On July 14, 2006, HELCO filed a memorandum in response to KDC's motion to participate. On July 7, 2006, the Rocky Mountain Institute ("RMI") filed its Motion to Intervene. On July 18, 2006, HELCO filed a memorandum in opposition to RMI's Motion to Intervene.

The Commission granted KDC's motion to participate, limited to those issues pertinent to HELCO's expansion of the Keahole generating station, by Order No. 22663 issued on August

1, 2006 ("Order No. 22663"). Order No. 22663 also granted participant status to RMI, limited to issues related to tiered rate pricing, time of use pricing, energy cost adjustment charge, net energy metering and REEEPAH. On November 29, 2006, RMI filed a notice of withdrawal. The Commission approved RMI's withdrawal in Order No. 23108, issued December 5, 2006.

5. The Schedule, Issues and Procedures

Following the request and granting of an extension of time, the parties and participant submitted their proposed Stipulated Prehearing Order on September 12, 2006, which included the issues, procedures and schedule for the proceeding, for Commission review and approval pursuant to Order No. 22663.

On September 28, 2006, the Commission issued Order No. 22903, which set forth the schedule for discovery and prehearing matters as well as the hearing itself (which generally followed but also modified the proposed stipulated prehearing order submitted on September 12, 2006). The schedule contemplated the submission of information requests ("IRs") to HELCO, and HELCO responses to IRs. Following the filing of written testimonies and exhibits by the Consumer Advocate, and a Statement of Position by KDC, and IR responses by the Consumer Advocate and KDC, HELCO would submit a settlement proposal to the Consumer Advocate and would engage in settlement discussions with the Consumer Advocate. HELCO would then file its written rebuttal testimonies and rebuttal IR ("RIR") responses and a Statement of Probable Entitlement. The Consumer Advocate would submit a response to HELCO's Statement of Probable Entitlement. Another round of settlement discussions would then occur between the Consumer Advocate and HELCO. Following settlement discussions, any agreements would be documented in a settlement letter, and the evidentiary hearings would commence the week of May 7, 2007.

The issues for the rate case included:

1. Is HELCO's proposed rate increase reasonable?

   a. Are the proposed tariffs, rates, charges and rules just and reasonable?

   b. Are the revenue forecasts for Test Year 2006 at present rates and proposed rates reasonable?

   c. Are the projected operating expenses for Test Year 2006 reasonable?

   d. Is the projected rate base for Test Year 2006 reasonable, and are the properties included in rate base used or useful for public utility purposes?

   e. Is the requested rate of return fair?

2. What is the amount of the Interim Rate Increase, if any, to which HELCO is probably entitled under §269-16(d) of the Hawaii Revised Statutes?

3. Whether HELCO's ECAC complies with the requirements of Act 162.

4. Whether the commission should adopt, modify, or decline to adopt, in whole or part, the standards for time-based metering and communications articulated in section 111(d)(14) of the Public Utility Regulatory Polices Act of 1978 ("PURPA"), as amended by the Energy Policy Act of 2005 ("EPACT") (16 U.S.C. §2621(d)(14)).

In Order No. 22903, the Commission noted that the nine-month deadline for the issuance of a final decision was February 5, 2007. The Commission construed the parties' agreement to schedule deadlines on or after February 5, 2007 as an agreement to waive the requirement that a final decision and order in this matter be issued within the nine-month period (i.e., by February 5, 2007) and approved such agreement.

By letter dated and filed on December 8, 2006, the parties submitted for approval an amended procedural schedule leading up to the evidentiary hearing. By Order No. 23153, issued

December 21, 2006, the Commission approved an amendment to the schedule of proceedings set forth in Order No. 22903. HELCO subsequently requested revisions to the schedule by letters dated March 19, 2007 and March 21, 2007. By Order No. 23315, issued March 23, 2007, the Commission approved an amendment to the schedule of proceedings.

6. The Written Testimonies and Responses to Information Requests

As stated above, HELCO's May 5, 2006 Application included the direct written testimonies of 21 witnesses, and accompanying exhibits and workpapers. In addition, on December 29, 2006, HELCO submitted its Act 162 supplemental testimonies and consultant report.

The Consumer Advocate conducted extensive discovery. The Consumer Advocate submitted nine sets of information requests, totaling over 580 individual requests, many with subparts, between July 25, 2006 and January 31, 2007. Many of the requests required HELCO to undertake significant efforts to compile and produce broad categories of information. Because the discovery requests were served on HELCO in successive waves, the Consumer Advocate was able to review HELCO's responses to the early rounds of discovery and then ask follow-up questions in the later sets of information requests.

HELCO provided confidential information pursuant to a protective order. On June 27, 2006, the parties jointly filed a Stipulated Protective Order for approval. By Order No. 22593 (June 30, 2006), the Commission approved the Stipulation for Protective Order ("Stipulated Protective Order").

In addition to submitting written responses to information requests, HELCO's witnesses and representatives participated in extensive meetings and telephone conferences with the consultants and representatives for the Consumer Advocate.

As a result of the change in schedule agreed to by the parties and approved by the Commission, the Consumer Advocate filed the written testimonies, exhibits and workpapers of its five witnesses on February 21, 2007. The Consumer Advocate proposed a rate increase of $16.6 million. The Consumer Advocate filed responses to HELCO's information requests on March 5 through 7, 2007.

As a result of their information requests, submission of pre-filed written testimonies, and responses to information requests, the Consumer Advocate also contributed substantially to the development of the prefiled record in this proceeding.

KDC filed its Position Statement dated February 20, 2007. KDC filed responses to HELCO's information requests on March 7, 2007.

On March 27, 2007, HELCO submitted the written rebuttal testimonies, exhibits and workpapers of 30 witnesses. Substitutions were made for three of the direct witnesses, due to a retirement, transfer of personnel and to reallocate witness responsibilities. In addition, nine witnesses were added on rebuttal in order to address various issues on the CT-4 and CT-5 units at the Keahole generating station. Further, rebuttal testimonies were not filed for one direct and two supplemental direct witnesses that had filed testimonies regarding rate design and matters relating to Act 162.

HELCO revised its revenue requirements in its rebuttal testimonies. The rebuttal testimonies and exhibits supported revenue requirements of $348,637,600 (based on February 1, 2006 fuel prices, an 8.33% return on average rate base and a 10.7% return on common equity.) The revised revenue requirements reflected a global settlement between HELCO and the Consumer Advocate with respect to all issues impacting revenue requirements. (The agreements reached with the Consumer Advocate are discussed below.) Given HELCO's estimated revenues at present rates of $324,073,100, the amount of the total rate increase that HELCO supported in rebuttal was $24,564,500, or 7.58%, over present rates for the normalized 2006 test year. HELCO RT-21 and HELCO-R-2101.

On March 27, 2007, HELCO also filed its Statement of Probable Entitlement. HELCO's Statement of Probable Entitlement incorporate agreements reached between HELCO and the Consumer Advocate through settlement discussions, which resolved all differences on revenue requirement issues in this proceeding, as explained in HELCO RT-1, filed on March 27, 2007. The settlement included the establishment of a pension tracking mechanism proposed by the Consumer Advocate (as explained by Mr. Steven Carver in CA-T-3 and Ms. Tayne Sekimura in HELCO RT-18) and an OPEB tracking mechanism (as explained by Ms. Sekimura in HELCO RT-18). Therefore, HELCO also requested that the Commission approve (1) the adoption of the pension and OPEB tracking mechanisms in its interim decision and order in this proceeding and (2) interim rates that incorporate the test year net periodic pension costs ("NPPC") of $2,744,000 and the test year net periodic benefit costs ("NPBC") of $1,530,400, and amortization of the pension asset of $2,554,000 (there is no corresponding "OPEB asset" to be amortized). With such approval, the tracking mechanisms would be adopted as of the date of the interim rate order.

On March 28, 2007, the Consumer Advocate filed its response to HELCO's Statement of Probable Entitlement that confirmed its agreement with HELCO on revenue requirements.

7. <u>Interim Decision and Order and the Stipulated Settlements</u>

On April 4, 2007, the Commission issued Interim Decision and Order No. 23342 ("Interim D&O"), which allowed HELCO to increase its rates on an interim basis to such levels as will produce, in the aggregate, $24,564,500 in additional revenues for the 2006 test year (or 7.58% over revenues at present rates for a normalized 2006 test year), effective from the date of the Interim D&O until the Commission issues a final decision in this docket. By the Interim D&O, the Commission also approved, on an interim basis, the adoption of the pension and Postretirement Benefits Other Than Pensions (also known as "OPEB") tracking mechanisms, and interim rates that incorporate the test year net periodic pension costs of $2,744,000, test year net periodic benefit costs of $1,530,400, and amortization of the pension asset of $2,554,000.

The tariff changes implementing the interim rate increase were filed and made effective on April 5, 2007. If the amount collected pursuant to the interim rate increase exceeds the amount of the increase approved in the final decision, then the excess must be refunded to HELCO's ratepayers, with interest.

On April 5, 2007, HELCO and the Consumer Advocate filed a stipulated settlement letter, which documented the agreement between HELCO and the Consumer Advocate on issues impacting the test year revenue requirements and certain rate design issues. On April 11, 2007, HELCO and the Consumer Advocate filed a stipulation that addressed matters such as the submission of written testimonies, the holding of an evidentiary hearing, and the submission of post-hearing written briefs.

KDC's attorney, Michael Matsukawa submitted a letter dated April 14, 2007 concerning a contested case hearing and public hearing. On April 17, 2007, KDC filed a (1) motion to amend Order No. 22663 to allow KDC greater participation in the rate case ("Motion to Amend Order 22663") and (2) partial objections to the stipulation entered into by HELCO and the Consumer Advocate ("Partial Objections") dated April 11, 2007. (KDC subsequently filed a withdrawal of Motion to Amend Order 22663 and withdrawal of Partial Objections, both dated May 8, 2007.)

On April 23, 2007, the Consumer Advocate filed a letter that (1) stated KDC was withdrawing its motions and was not requesting a response to KDC's April 14, 2007 letter, and (2) proposed amendments to the schedule of proceedings (e.g., providing an opportunity for KDC to file a second statement of position in response to HELCO's rebuttal testimonies, and HELCO and the Consumer Advocate having the opportunity to file a response to KDC's second statement of position). Order No. 23411 issued May 3, 2007 approved the agreements set forth in the Consumer Advocate's April 23, 2007 letter. KDC filed a Responsive Statement to Rebuttal Testimony of HELCO dated April 28, 2007. HELCO filed a Response to KDC's Responsive Statement on May 11, 2007. On May 11, 2007, the Consumer Advocate filed a letter that stated it had no comments on KDC's Responsive Statement.

On May 15, 2007, HELCO and the Consumer Advocate filed a settlement letter that documented the parties' agreements on the remaining rate design issues in this proceeding.

8. <u>The Stipulated Settlements</u>

By letter agreement dated and filed on April 5, 2007 (the "Stipulated Settlement Letter"), the Consumer Advocate and HELCO documented the areas in which HELCO and the Consumer Advocate had reached agreement on issues impacting the test year revenue requirement and agreement reached on certain rate design issues. The Stipulated Settlement Letter also stated that discussions on the remaining rate design issues were continuing and the parties would file a separate stipulated settlement letter to document the agreements reached on those remaining issues. Following additional discussions between HELCO and the Consumer Advocate on the remaining rate design issues, on May 15, 2007, HELCO and the Consumer Advocate filed a settlement letter that documented the parties agreements on the remaining rate design issues in this proceeding ("Rate Design Stipulated Settlement Letter") (the Stipulated Settlement Letter and Rate Design Stipulated Settlement Letter are collectively referred to as the "Stipulated

Settlement Letters").

Under the Stipulated Settlement Letters, the parties agreed to accept for the purpose of settlement some of the positions that they had initially opposed and to reach mutually-acceptable compromises on other issues. The details of the Stipulated Settlement Letters will be discussed below in the remaining sections of this brief.

In the Stipulated Settlement Letters, the parties agreed "that the rate changes specifically set forth in this Stipulated Settlement result in just and reasonable rates for HELCO's regulated electric operations." HELCO fully supports the settlement reached by the parties, and urges the Commission to approve them in their entirety.

The Stipulated Settlement Letters provide that, if the Commission does not issue an order adopting all material terms of the stipulated settlements, each or both of the parties may withdraw from the stipulations, and such party or parties may pursue their respective positions on HELCO's application without prejudice. (For the purposes of the Stipulated Settlement Letters, whether a term is material is left to the discretion of the party choosing to withdraw from the Stipulation.) The settlement was the culmination of a process that began with the IRs, continued with the testimonies of the Consumer Advocate and its responses to IRs, and concluded with the settlement itself.

In reviewing the settlement, the Commission should review it as a whole, as the parties did, and not as a series of isolated, unrelated agreements. Such a review would be consistent with the "end result" standard applicable to ratemaking, which the U.S. Supreme Court articulated in <u>Federal Power Comm'n v. Hope Natural Gas</u>, 320 U.S. 591 (1944).

The settlement also should be reviewed in the light of past Commission practice and policy, which have favored negotiated settlements by parties capable of adequately representing their constituencies. That was certainly the case in this proceeding, as the Consumer Advocate was extraordinarily thorough in its investigation of the proposed rate increase. The Consumer Advocate retained experienced consultants to review the various components of the revenue requirements and rate design issues. HELCO responded to over 580 IRs and SIRs, with numerous subparts. By any measure, there is no question that the Consumer Advocate took full advantage of the discovery process and that the information provided by HELCO in response to the discovery requests produced an extensive record on which the Commission can evaluate the settlement agreements between the parties.

As a result, the Consumer Advocate and HELCO were able to work together to achieve a fair and workable settlement on all issues.

9. Remaining Sections of the Opening Brief

The stipulated agreements with the Consumer Advocate with respect to revenues, expenses, rate base, rate of return and rate design are presented in Part II of this Opening Brief.

The only remaining issue with respect to revenue requirements arises out of the position of KDC (which did not join in the stipulated settlement on revenue requirements) that additional costs for CT-4 and/or CT-5 should be written down. There is no basis for requiring any further write down of these costs. Since this is still an issue, however, HELCO has summarized in some detail the exhaustive testimonies and exhibits that it submitted to address this issue in Part III of this Opening Brief.

HELCO's ECAC (and its compliance with Act 162 is not a remaining issue in this proceeding, and there does not appear to be any issue with respect to the EPAct standards for time-based metering and communications. Since the Commission is expected to make certain findings with respect to these legislatively added issues, HELCO also has summarized the evidence presented on these issues in some detail in Part IV of this Opening Brief.

As a result of the complete settlement between HELCO and the Consumer Advocate, the two parties have agreed not to submit reply briefs.

II. REVENUE REQUIREMENTS

A. REVENUES

1. Sales

HELCO's estimate of total electricity sales for the 2006 test year is 1,148.0 gigawatthours ("GWH"). HELCO-201; HELCO T-2 at 1. The Consumer Advocate agrees with HELCO's test year estimate of total electricity sales. Stipulated Settlement Letter, Exhibit 1 at 1.

HELCO's estimate of the average number of total customers for the 2007 test year is 74,174. HELCO-206; HELCO T-2 at 11. The Consumer Advocate agrees with HELCO's test year estimate of the average number of total customers. Stipulated Settlement Letter, Exhibit 1 at 1.

2. Revenues

a. Electric Sales Revenues

HELCO's 2006 test year total electric sales revenues, based on the test year sales estimate and average number of customers, are $323,147,700 at present rates. HELCO-R-301; HELCO RT-3 at 2. The Consumer Advocate accepts HELCO's 2006 test year total electric sales revenues at present rates as shown on HELCO-R-301. Stipulated Settlement Letter, Exhibit 1 at 1.

HELCO-301 provides HELCO's 2006 test year electric sales revenues at present rates, based on the test year sales estimate and average number of customers in HELCO-201 and HELCO-206. The Consumer Advocate proposed an adjustment of $4,385,000 to Energy Cost Adjustment Clause ("ECAC") revenues in CA-101, Schedule C-2, based on an Energy Cost

Adjustment Factor ("ECAF") of 8.621¢/kwh at present rates. For purposes of settlement, the Consumer Advocate agrees with HELCO's ECAF of 8.998¢/kwh at present rates as shown on HELCO-R-2201, the sales heat rates shown on HELCO-R-2205, and the resulting ECAC revenues of $103,297,000 at present rates shown on HELCO-R-302. The agreements result in a decrease of $58,000 in test year ECAC revenues at present rates. The Company also increased electric sales revenue by $21,000 to update Rider M subscribership. As a result, the Consumer Advocate accepts HELCO's 2006 test year electric sales revenue estimate of $323,147,700 at present rates shown on HELCO-R-301. Stipulated Settlement Letter, Exhibit 1 at 1.

b. <u>Other Operating Revenues</u>

In direct testimony, HELCO's 2006 test year other operating revenues was $904,400 at present rates. HELCO-710. The Consumer Advocate proposed an adjustment of $21,000 to update revenues according to an extrapolation of August 2006 year-to-date actuals. For purposes of settlement, the Company accepted this adjustment. The resulting test year estimate for other operating revenues at present rates is $925,400 (before the adjustment for the increased non-sales related charges proposed by the Consumer Advocate), as shown at HELCO-R-706. Stipulated Settlement Letter, Exhibit 1 at 1.

The Consumer Advocate proposed that HELCO adopt the increased non-sales related charges that were proposed by HECO in Docket No. 04-0113. For purposes of settling these issues in this proceeding, HELCO was willing to agree with the Consumer Advocate's proposal to increase the non-sales related charges (i.e., Returned Payment Charge, Field Collection Charge, and Service Establishment Charges) to the levels proposed by HECO in Docket No. 04-0113. The Consumer Advocate did not object to revising the Returned Check Charge to a Returned Payment Charge or to multiplying a factor of .17% to the electric sales revenues at proposed rates to determine Late Payment Charges at proposed rates. HELCO and the Consumer Advocate agree that the resulting test year other operating revenues at proposed rates are $1,096,500, as shown in HELCO-R-706. Stipulated Settlement Letter, Exhibit 1 at 1-2.

B. EXPENSES

1. Fuel and Purchased Power Expense

a. Fuel Expense

HELCO's 2006 test year estimate of fuel oil expense is $78,090,700 (based on February 1, 2006 fuel oil prices), and HELCO's 2006 test year estimate of fuel related expense is $492,800 for a total fuel expense of $78,583,500. Stipulated Settlement Letter, Exhibit 1 at 2; HELCO RT-4 at 2; HELCO-R-401 to 405. The test year fuel expense represents the cost of fuel required by HELCO to produce the energy required, less purchased energy, to meet the projected needs of HELCO's customers. The two primary factors in the determination of the test year fuel expense are fuel price and projected fuel consumption (i.e., the quantity of fuel needed to produce the required energy). The derivation of fuel expense is discussed in HELCO T-4 on pages 17 through 46 and in HELCO RT-4 on pages 6 through 15 and HELCO-R-401 through HELCO-R-405.

The Consumer Advocate accepts HELCO's test year estimate of fuel oil expense of $78,090,700 (based on February 1, 2006 fuel oil prices), and HELCO's 2006 test year estimate of fuel related expense of $492,800 for a total fuel expense of $78,583,500. Stipulated Settlement Letter, Exhibit 1 at 2.

For purposes of settlement, the Consumer Advocate accepts HELCO's use of its production simulation model, and the results of this model as reflected in HELCO RT-4 (e.g., HELCO-R-401).

HELCO agrees to continue filing the annual calibration factor reports required by the

Commission in Decision and Order No. 18365 (pages 18 to 19) filed on February 8, 2001 in Docket No. 99-0207. Stipulated Settlement Letter, Exhibit 1 at 2.

b. Purchased Power Expense

HELCO's 2006 test year estimate of purchased power expense is $117,210,000. HELCO RT-5 at 11; HELCO-R-548. The derivation of purchased power expense is discussed in HELCO T-5 on pages 82 through 96 and in HELCO RT-5 on pages 11 through 13.

The estimate of purchased energy is 709,256 GWh. HELCO RT-4 at 2, 36. The purchased power expense is comprised of purchased energy expense of $99,280,000, and purchased capacity expense of $17,930,000. HELCO RT-5 at 11; HELCO-R-548. HELCO's test year estimate is based on HELCO's rebuttal testimony production simulation as explained in HELCO RT-4.

For purposes of settlement, the Consumer Advocate has agreed with HELCO's purchased power test year estimate of $117,210,000. Stipulated Settlement Letter, Exhibit 1 at 2.

c. Generation Heat Rate

HELCO's 2006 test year net generation heat rates are 13,600 Btu/kWh for central station generation, 14,324 Btu/kWh for steam generation, and 12,407 Btu/kWh for diesel generation. HELCO-R-406.

The sales heat rate is the heat content of the fuel consumed (in Btu's) per kwh of sales. The sales heat rate, in the form of a Generation Efficiency Factor, is used in the Energy Cost Adjustment Clause ("ECAC") to translate the base generation cost in cents per Mbtu to the weighted base generation cost in cents per kwh of sales. HELCO T-4 at 47-48. The Generation Efficiency Factor is 0.015615 MBtu/kWh for steam generation, 0.013526 MBtu/kWh for diesel generation, and 0.014826 MBtu/kWh for wind/hydro. HELCO-R-406.

For purposes of settlement, the Consumer Advocate agrees with HELCO's use of its production simulation model and with the results from this model as reflected in HELCO RT-4. Stipulated Settlement Letter, Exhibit 1 at 2. The Consumer Advocate also agrees with HELCO's sales heat rates shown in HELCO-R-2205. Stipulated Settlement Letter, Exhibit 1 at 1.

d. Energy Cost Adjustment Factor

HELCO's 2006 test year Energy Cost Adjustment Factor ("ECAF") at present and proposed rates are 8.998¢/kwh and 0.00 ¢/kwh, respectively. HELCO RT-22 at 2; HELCO-R-2201.

The Consumer Advocate agrees that the ECAF at present rates is 8.998¢/kwh. The parties agree that the ECAC should continue and that it satisfies Act 162 (Session Laws of Hawaii, 2006), and agree to the methodology to calculate the ECAF, including the addition of the "DG Component" and propane start-up costs in such calculation, as proposed in HECO RT-22. Stipulated Settlement Letter, Exhibit 1 at 1.

2. Production and T&D Expenses

a. Production Expenses

HELCO's 2006 test year estimate for Production O&M expenses (other than fuel oil and purchased power expense) is $21,041,000. Stipulated Settlement Letter, Exhibit 1 at 2; HELCO-R-501. HELCO and the Consumer Advocate agree that the 2006 test year estimate for Production O&M expenses (other than fuel oil and purchased power expenses) is $21,041,000.

In its response to CA-IR-447, the Company made adjustments totaling ($1,303,000), to which the Consumer Advocate agreed. In addition the Consumer Advocate made three adjustments:

- ($185,000) as calculated in CA-101, Schedule C-4 to reduce test year production O&M labor expenses based on actual 2006 labor expense information in HELCO's response to

CA-SIR-5.

- ($382,000) as calculated in CA-101, Schedule C-5 to reduce non-labor materials expense based on an average of recorded materials expenses for the period 2004-2006.
- ($130,000) as shown in CA-101, Schedule C-6 to remove LPT turbine replacement overhaul costs.

Although the Company did not initially agree with the Schedule C-5 adjustment asserting that it did not consider the impact of other non-labor expenses and did not use the same methodology as the Schedule C-4 adjustment to the production O&M labor expenses, HELCO agreed to the three adjustments to minimize the number of issues in this proceeding and to reach settlement. HELCO and the Consumer Advocate agree that these adjustments result in a test year production O&M expense of $21,041,000, as shown in HELCO-R-501.

HELCO's test year estimate is broken down as follows:

	Labor ($000)	Non-Labor ($000)	Total ($000)
Production Operations	$5,780	$ 3,540	$ 9,320
Production Maintenance	$2,925	$ 8,796	$11,721
TOTAL	$8,705	$12,336	$21,041

Stipulated Settlement Letter, Exhibit 1 at 2; HELCO-R-501.

b. Transmission and Distribution Expenses

HELCO's 2006 test year estimate for Transmission and Distribution ("T&D") O&M expense is $8,705,000. Stipulated Settlement Letter, Exhibit 1 at 2-3; HELCO-R-601. HELCO and the Consumer Advocate agree that the 2006 test year estimate for T&D O&M expense is $8,705,000. Stipulated Settlement Letter, Exhibit 1 at 3.

In its response to CA-IR-447, the Company made adjustments totaling ($132,000) to its test year T&D expense. The Consumer Advocate accepted the adjustment as shown on Schedule C-14. Stipulated Settlement Letter, Exhibit 1 at 2.

The Consumer Advocate also proposed an adjustment of ($326,000) in CA-101, Schedule C-19 to remove its estimate of labor costs for unfilled T&D positions. The Company disagreed with the adjustment, stating that its rebuttal testimony test year T&D O&M labor expense estimate (before settlement) of $3,372,000 was significantly less than the actual T&D O&M labor expense incurred in 2006 of $3,652,000. For purposes of settlement, HELCO and the Consumer Advocate agreed to an adjustment of ($163,000). Stipulated Settlement Letter, Exhibit 1 at 3.

With these two adjustments, HELCO and the Consumer Advocate agree that the test year T&D expense is $8,705,000, as shown on HELCO-R-601. Stipulated Settlement Letter, Exhibit 1 at 3.

The breakdown of HELCO's test year estimate is as follows:

	Labor ($000)	Non-Labor ($000)	Total ($000)
Transmission Operations	446.6	483.9	930.5
Transmission Maintenance	432.6	977.6	1,410.2
Total	879.2	1,461.5	2,340.7
Distribution Operations	1,082.2	1,240.7	2,322.9
Distribution Maintenance	1,247.5	2,793.6	4,041.1
Total	2,329.7	4,034.3	6,364.0
Grand Total	3,208.9	5,495.8	8,704.7

Stipulated Settlement Letter, Exhibit 1 at 2-3; HELCO-R-601.

3. Customer Accounts and Customer Service Expense

a. Customer Accounts Expenses

HELCO's 2006 test year estimate for Customer Accounts Expense (excluding uncollectibles) is $3,186,000. HELCO-701; HELCO-R-702. HELCO and the Consumer Advocate agree that the 2006 test year estimate for Customer Accounts Expense is $3,186,000. Stipulated Settlement Letter, Exhibit 1 at 3.

The 2006 test year estimates for Accounts 901 through 903 is as follows:

Account	Total ($000)
901 Supervision	$ 128
902 Meter Reading	$ 742
903 Customer Records & Collection	$2,316
Total	$3,186

Stipulated Settlement Letter, Exhibit 1 at 3; HELCO-701; HELCO-R-702.

HELCO's 2006 test year estimate for uncollectible expense at present rates is $388,000. HELCO-701; HELCO-R-702. HELCO and the Consumer Advocate agree that the 2006 test year estimate for uncollectible expense at present rates is $388,000. Stipulated Settlement Letter, Exhibit 1 at 3.

b. Customer Service Expense

HELCO's 2006 test year estimate for Customer Service Expense is $1,508,800. HELCO-R-801. HELCO and the Consumer Advocate agree that the 2006 test year estimate for Customer Service Expense is $1,508,800. Stipulated Settlement Letter, Exhibit 1 at 4.

c. Stipulated Settlement Letter

The following sections provide a brief discussion of the agreements reached in the Stipulated Settlement Letter concerning customer service expenses.

DSM Administration Costs

To minimize the issues in this proceeding, the Company agrees with the Consumer Advocate's proposed adjustment of ($168,000) in CA-101, Schedule C-9 to reclassify the DSM administration costs for recovery through the DSM surcharge mechanism. Stipulated Settlement Letter, Exhibit 1 at 3.

REEEPAH

In response to the Consumer Advocate's concerns with including the costs of REEEPAH in the test year revenue requirements, HELCO agrees to remove its test year estimate of $500,000 for REEEPAH expenses (as proposed in CA-101, Schedule C-10). HELCO will include the REEEPAH in HELCO's IRP-3, rather than seek Commission approval of the program in the instant rate proceeding. Should the Commission approve HELCO's request to implement the REEEPAH in HELCO's IRP-3, HELCO will recover the costs of the program implementation through a Renewable Energy Programs Adjustment clause in the Integrated Resource Planning ("IRP") Cost Recovery Provision. Stipulated Settlement Letter, Exhibit 1 at 3.

CHP Support and Customer Service Projects

In CA-101, Schedule C-11, the Consumer Advocate accepted the Company's adjustment of ($29,000) in its response to CA-IR-447 to reduce combined heat and power ("CHP") project support costs. For customer service projects, the Consumer Advocate extrapolated October 2006 year-to-date actual billings to 12 months to determine its ($67,000) adjustment to the $93,000 test year estimate in HELCO's direct testimony. The Company proposed to use the recorded December 2006 year-to-date amount of $47,000 in lieu of the Consumer Advocate's extrapolated amount. This results in a ($46,000) adjustment for customer service projects which the

Consumer Advocate accepted for the purposes of settlement. The sum of the CHP support and customer service project adjustments is ($75,000). Stipulated Settlement Letter, Exhibit 1 at 3.

4. Administrative and General Expense

HELCO's 2006 test year estimate for total Administrative and General ("A&G") Expense is $15,214,000. HELCO-R-901. HELCO and the Consumer Advocate agree that the 2006 test year estimate for A&G Expense is $15,214,000. Stipulated Settlement Letter, Exhibit 1 at 4.

a. Administrative Expenses

HELCO's estimate of Administrative Expenses for the 2006 test year for Accounts 920, 921 and 922 is $2,141,000. HELCO-R-901. The estimates, by accounts, are as follows:

Account	Description	($000)
920	A&G Salaries	$2,300
921	A&G Supplies & Expense	$ 756
922	A&G Transferred to Construction	($915)
Total		$2,141

HELCO-R-901; HELCO-R-902 at 1.

The Consumer Advocate agrees with HELCO's 2006 test year estimate of Administrative Expenses. Stipulated Settlement Letter, Exhibit 1 at 4.

b. Outside Services

HELCO's estimate of Outside Services for the 2006 test year for Accounts 92301, 92302 and 92303 is $1,981,000. The estimates, by accounts, are as follows:

Account	Description	($000)
92301	Outside Legal Services	$ 66
92302	Other Outside Services	$ 204
92303	Services From Assoc. Co.	$1,710
Total		$1,981

HELCO-R-901; HELCO-R-902 at 2.

The Consumer Advocate agrees with the 2006 test year estimate for outside services.

Stipulated Settlement Letter, Exhibit 1 at 4.

c. Insurance

HELCO's 2006 test year estimates for insurance are as follows:

Account	Description	($000)
924.00	Property Insurance	$ 536
925.00	Injuries/Damage -Employees/Public	$1,913
Total Insurance		$2,449

HELCO-R-901; HELCO-R-902 at 3.

The Consumer Advocate agrees with the 2006 test year estimate for insurance. Stipulated Settlement Letter, Exhibit 1 at 4.

d. Miscellaneous A&G Expenses

HELCO's 2006 test year estimates for Miscellaneous A&G Expenses are as follows:

Account	Description	($000's)
928	Regulatory Commission Expense	$316.0
9301	Inst. Or Goodwill Advertising Expense	$ 0.0
9302	Miscellaneous General Expenses	$500.1
932	Admin and General Maintenance	$156.4
Total Miscellaneous		$972.5

HELCO-R-901; HELCO-R-902 at 7.

The Consumer Advocate agrees with the 2006 test year estimate for Miscellaneous A&G Expenses. Stipulated Settlement Letter, Exhibit 1 at 4.

e. Stipulated Settlement Letter

The following sections provide a brief discussion of the agreements reached in the Stipulated Settlement Letter concerning A&G expenses.

Pension Tracking Mechanism

HELCO and the Consumer Advocate agree on the implementation of a pension tracking mechanism as proposed by the Consumer Advocate. In addition, HELCO and the Consumer

Advocate agree to implement an OPEB tracking mechanism as proposed by the Company in the rebuttal testimony of Ms. Tayne Sekimura (HELCO RT-18) and documented in HELCO-R-1808, HELCO-R-1809, HELCO-R-1810 and HELCO-R-1811. The Consumer Advocate and HELCO agree that upon Commission approval of the pension tracking mechanism HELCO's test year revenue requirement would include $2,554,000, which is the amortization of the ending pension asset balance (ending pension asset of $12,771,000 divided by 5), in addition to the test year net periodic pension cost ("NPPC") of $2,744,000, as explained in HELCO RT-9 and HELCO RT-18. Stipulated Settlement Letter, Exhibit 1 at 4.

T&D Training Expense and A&G Corrections

The Consumer Advocate and HELCO agree on the following two adjustments in CA-101:

- C-15 – ($131,000) adjustment for T&D training based on HELCO responses to CA-IR-447 and CA-SIR-35, which reduced the estimated T&D training expense to 2006 actual levels.

- C-21 - $321,000 adjustment for A&G corrections based on the Company's response to CA-IR-447. Stipulated Settlement Letter, Exhibit 1 at 4.

5. **Employee Benefits**

a. **Introduction**

HELCO's 2006 test year estimate for employee benefits costs are as follows:

Account	Description	($000)
926000	Employee Benefits – Flex Credits	$ (368.2)
926010	Employee Pensions – Nonfunded	$ 0.0
926020	Employee Benefits – Dental Plan	$ 315.4
926030	Employee Pension - Funded	$ 5,298.3
926040	Employee Group Life Insurance	$ 300.2
926050	Employee Group Med & Hospital Insurance	$ 1,973.2
926060	Other Employee Benefits	$ 634.0

926070	Employee Vision	$ 49.5
926080	Long-Term Disability Plan	$ 183.3
926090	Post-Retirement Benefits	$ 1,410.4
92690	Employee Benefits Transferred to Construction	($2,125.1)
TOTAL		$7,671.0

HELCO-R-901; HELCO-R-902 at 4-5.

The Consumer Advocate agrees with HELCO's 2006 test year estimates for employee benefits costs. See Stipulated Settlement Letter, Exhibit 1 at 4.

6. Depreciation And Amortization

HELCO's 2006 test year estimate for Depreciation and Amortization expense is $28,772,000. HELCO-R-1201. The Consumer Advocate agrees with HELCO's 2006 test year estimate for Depreciation and Amortization expense. Stipulated Settlement Letter, Exhibit 1 at 4.

a. Stipulated Settlement Letter

Keahole Generating Station

The Consumer Advocate proposed adjustments totaling ($1,088,000) (in CA-101, Schedules C-17 and C-18) to depreciation expenses based on its proposed write down of $22,373,000 (net of accumulated depreciation) for CT-4 and CT-5 investments at the Keahole Generation Station. As described in a later section, HELCO and the Consumer Advocate settled on a write down of $12,000,000 (net of accumulated depreciation) for the CT-4 and CT-5 costs. The parties agreed that the depreciation adjustment would be ($598,000) as shown on HELCO-RWP-1205. Stipulated Settlement Letter, Exhibit 1 at 4.

SFAS 109 Regulatory Asset

HELCO adjusted the amortization of the net SFAS 109 regulatory asset by ($4,000) to reflect the actual 2006 amount of $357,000 as shown in HELCO-R-1201. The Consumer

Advocate agreed with the adjustment. Stipulated Settlement Letter, Exhibit 1 at 4.

7. **Taxes**

a. **Taxes Other Than Income Taxes**

The taxes included in Taxes Other Than Income Taxes are payroll taxes for (1) the Federal Insurance Contribution Act and Medicare ("FICA/Medicare") tax, (2) the Federal Unemployment ("FUTA") Tax, (3) the State Unemployment ("SUTA") tax, and revenue taxes consisting of (a) the State Public Service Company ("PSC") tax, (b) the State Public Utility ("PUC") fee, and (c) the County Franchise Royalty ("Franchise") tax. HELCO T-13 at 1-2.

HELCO's 2006 test year estimate of Taxes Other Than Income Taxes at present rates is as follows:

PSC Tax	$19,049,000
Public Utility Fee	1,618,000
Franchise Tax	8,069,000
Payroll Tax	1,442,000
Total Taxes Other Than Income Taxes	$30,178,000

HELCO-R-1301.

The Consumer Advocate and HELCO agree on a test year estimate of $30,178,000 for taxes other than income taxes. Stipulated Settlement Letter, Exhibit 1 at 5.

Stipulated Settlement Letter

The Consumer Advocate proposed an adjustment of ($100,000) to payroll taxes as shown on CA-101, Schedule C-12. For settlement purposes the Company agrees with the Consumer Advocate's FICA/Medicare adjustment calculation. The T&D labor adjustment amount at line 6 has been revised to ($163,000) to reflect the agreement reached on the T&D labor adjustment. The resulting FICA/Medicare tax adjustment is ($80,000). Stipulated Settlement Letter, Exhibit 1 at 5.

Although the Company does not agree with the use of an employee count of 340 to calculate the FUTA/SUTA taxes, for settlement purposes, it agrees with the Consumer Advocate's adjustment of ($8,000) as shown on CA-101, Schedule C-12. Stipulated Settlement Letter, Exhibit 1 at 5.

The Company agrees with the Consumer Advocate's adjustment to correct revenue taxes at present rates for a bad debt deduction as shown on CA-101, Schedule C-13. The Consumer Advocate proposed a ($25,000) reduction in revenue taxes. The Company recalculated the adjustment according to the changes in electric sales and other operating revenues as explained above and determined the amount to be ($27,000). Stipulated Settlement Letter, Exhibit 1 at 5.

b. <u>Income Taxes</u>

The income tax calculation is based on the "short form" method that has been consistently adopted by the Commission in previous rate cases, including HELCO's D&O No. 18365 (February 8, 2001) in Docket No. 99-0207, MECO's D&O No. 16922 (April 6, 1999) in Docket No. 97-0346 and D&O No. 14412 (December 11, 1995) in Docket No. 7766. The "short form" method simplifies the calculation of income tax expense by utilizing net operating income before income taxes, with certain adjustments which are explained below. The resulting amount is taxable income for ratemaking purposes. Taxable income for ratemaking purposes is multiplied by the composite federal/state income tax rate of 38.9097744%. This product is then reduced by the test year amortization of state capital goods excise tax credits ("state ITC"), net of tax. The resulting amount is the income tax expense utilized in deriving net operating income for ratemaking purposes. HELCO T-13 at 5-6.

HELCO's estimated 2006 test year income tax expense is $3,624,000 at present rates. HELCO RT-13 at 7; HELCO-R-1302.

HELCO's estimate of the amortization amount for the State Capital Goods Excise Tax Credit for the 2006 test year at present rates is $490,000. HELCO-R-1302; HELCO-R-2101. The capital goods excise tax credit was enacted in 1987 under H.R.S. §235-110.7 and was designed to track the qualification rules of the old federal investment tax credit ("ITC"). The four percent credit is earned on qualifying equipment purchased and placed into service by businesses in Hawaii. For book and ratemaking purposes, the credit is deferred in the year earned and, subsequently, amortized over the estimated useful life of the related assets as was done with federal ITC. The amortization on new additions begins when the book depreciation commences on those additions. HELCO T-13 at 9-10.

HELCO's 2006 test year interest expense estimate is $10,021,000. HELCO-R-1302; HELCO-RWP-1302 at 1. The interest expense test year estimate is calculated based on the same methodology used by both HELCO and the Consumer Advocate in Docket No. 99-0207 and used by the Commission in determining HELCO revenue requirements in that docket. This method estimates the amount of interest expense by calculating the interest on the long-term debt and hybrid securities actually in place and on the estimated additional long-term debt and short-term debt to be required in the test year. This total interest is then reduced by the debt portion of the Allowance for Funds used during Construction ("AFUDC") for the year. HELCO T-13 at 7-8.

The Consumer Advocate and HELCO agree on the methodology for the calculation of income taxes, including the computation of the interest expense adjustment. HELCO RT-13 at

3.

c. **Stipulated Settlement Letter**

At CA-101, Schedule C-20, the Consumer Advocate proposed an adjustment to account for tax savings that were created by the American Jobs Creation Act of 2004. Although the Company does not agree with the Consumer Advocate's calculation of the adjustment and questioned whether the Section 199 income tax deduction would apply once the final test year numbers are established, the Company agrees to the Consumer Advocate's ($160,000) adjustment for the purpose of minimizing the issues in this proceeding. Stipulated Settlement Letter, Exhibit 1 at 5.

C. **RATE BASE**

1. **Introduction**

HELCO's estimate of its test year 2006 average rate base is $360,409,000 at present rates and $357,239,000 at proposed rates. HELCO RT-16 at 1, 13; HELCO-R-1601.

HELCO generally calculates the test year rate base in accordance with the concepts adopted by the Commission in prior rate case decisions, including Decision and Order No. 18365 (dated February 8, 2001) in Docket No. 99-0207, HELCO's test year 2000 rate case; Decision and Order No. 15480 (dated April 2, 1997) in Docket No. 94-0140, HELCO's test year 1996 rate case; and Decision and Order No. 13762 (dated February 10, 1995) in Docket No. 7764, HELCO's test year 1994 rate case. HELCO T-16 at 2.

The rate base is calculated as the sum of the average balances for the following investments in assets:

1) Net cost of plant in service,

2) Property held for future use,

3) Fuel inventory,

4) Materials and supplies inventories,

5) Unamortized net Statement of Financial Accounting Standards ("SFAS") 109 regulatory asset,

6) Pension asset,

7) Unamortized net other postretirement benefits other than pensions ("OPEB") amount, and

8) Working cash

less the sum of the average balances for the following funds from non-investors:

1) Unamortized contributions in aid of construction ("CIAC"),

2) Customer advances for construction,

3) Customer deposits,

4) Accumulated deferred income taxes, and

5) Unamortized investment tax credits.

HELCO RT-16 at 2-7.

HELCO's average rate base at present rates is as follows:

2006 Average Rate Base
($Thousands)

Investments in Assets Serving Customers	12/31/2005	12/31/2006	Average For Test Year
Net Cost of Plant in Service	$439,895	$456,696	$448,296
Property Held for Future Use	129	129	129
Fuel Inventory	8,241	8,241	8,241
Materials & Supplies Inventories	3,322	3,377	3,350
Unamort. Net SFAS 109 Reg. Asset	10,888	10,655	10,772
Pension Asset	15,515	12,771	14,143
OPEB Amount	0	0	0
Working Cash at Present Rates	2,460	2,460	2,460
Total Investments in Assets	$480,450	$494,329	$487,390
Funds From Non-Investors			
Unamortized CIAC	$ 56,925	$ 59,936	$ 58,431
Customer Advances	28,597	31,780	30,189
Customer Deposits	920	941	931
Accumulated Deferred Income Taxes	26,108	25,631	25,870
Unamortized ITC	11,247	11,877	11,562
Total Deductions	$123,797	$130,165	$126,981
Average Rate Base at Present Rates			$360,409

HELCO-R-1601.

The parties agree on the 2006 test year average rate base estimate.

2. Additions To Rate Base

a. Introduction

In this case, the following are the uses of funds from investors that are added to the rate base: (1) Net Cost of Plant in Service, (2) Property Held for Future Use, (3) Fuel Inventory, (4) Materials and Supplies Inventory, (5) Unamortized Net SFAS 109 Regulatory Asset, (6) Pension Asset, (7) OPEB Amount, and (8) Working Cash.

b. Net Cost Of Plant In Service

HELCO's average 2006 test year Net Cost of Plant in Service is $448,296,000. HELCO-R-1601; HELCO-R-1602. HELCO discussed the method used to calculate the average Net Cost of Plant in Service in HELCO T-16 on pages 3 through 5.

The Stipulated Settlement Letter discusses the agreements reached with respect to this subject. In Schedules B-7 and B-8 in CA-101, the Consumer Advocate proposed adjustments to remove $24,007,000 associated with the cost of the Keahole CT-4 and CT-5 generating units from plant in service (and to remove the associated accumulated depreciation of $1,634,000) on an average test year basis. HELCO's position was that there should be no adjustments to the CT-4 and CT-5 plant in service amounts. For the purposes of reaching a settlement, HELCO and the Consumer Advocate agreed to an adjustment of ($12,898,000) of gross plant in service, less $898,000 of average accumulated depreciation for 2006 – i.e., ($12,000,000) of plant in service net of average accumulated depreciation – associated with the cost of the CT-4 and CT-5 units at the Keahole generating station. Stipulated Settlement Letter, Exhibit 1 at 5.

At CA-101, B-1, the Consumer Advocate proposed an average test year adjustment of $1,205,000 to update plant additions according to 2006 recorded amounts. HELCO reasoned that all items constituting the test year net cost of plant in service should be updated to 2006 recorded amounts as shown in HELCO-R-1602. As part of an overall settlement, the Consumer Advocate agrees to update those items to reflect the 2006 recorded amounts. Stipulated Settlement Letter, Exhibit 1 at 6.

c. Property Held for Future Use

Property held for future use ("PHFFU") is property owned by HELCO and held for future utility purposes. It represents HELCO's investment in sites needed to provide electric service in the future. HELCO T-16 at 5.

HELCO's average 2006 test year balance for property held for future use is $129,000. HELCO-R-1601. As reflected in HELCO-R-1601, HELCO proposed to adjust the average test year balance for property held for future use up to $129,000 from $64,500 to reflect that the Palani substation project was not completed in 2006. The $64,500 included in the average test year property held for future use balance in the Company's direct testimony was based on $129,000 included in the 12/31/05 balance and $0 included in the 12/31/06 balance. Since the test year plant additions will be based on actuals, the Palani substation project will not be included in plant in service, and the Palani substation site will continue to be included in property held for future use. For purposes of settlement, the Consumer Advocate agrees with this adjustment. Stipulated Settlement Letter, Exhibit 1 at 6.

d. <u>Fuel Inventory</u>

HELCO's estimate of the average fuel inventory for the 2006 test year is $8,240,900. HELCO-R-401; HELCO-R-408 at 1. For purposes of settlement, the Consumer Advocate accepts HELCO's average test year balance of $8,240,900 as shown on HELCO-R-401. HELCO's test year estimate is based on its rebuttal testimony production simulation as explained in HELCO RT-4. Stipulated Settlement Letter, Exhibit 1 at 6.

e. <u>Materials and Supplies Inventories</u>

HELCO's 2006 test year estimate of average materials and supplies inventories is $3,350,000. HELCO-R-1605. In its response to CA-IR-448, HELCO corrected its calculation of the test year materials and supplies (T&D and production) inventories to reflect the average of the month-end values of the material and supply inventory for the 13-month period ending December 31, 2006. The Consumer Advocate accepted the adjustment for the T&D inventory but based on its response to HELCO/CA-IR-111, did not accept the adjustment for production inventory. For purposes of settlement, HELCO and the Consumer Advocate agree on the resulting average 2006 test year estimate of $3,350,000 for materials and supplies inventories. Stipulated Settlement Letter, Exhibit 1 at 6.

f. Unamortized Net SFAS 109 Regulatory Asset

HELCO's estimate of the average Unamortized Net SFAS 109 Regulatory Asset is $10,772,000 for the 2006 test year. HELCO-R-1305. As shown in HELCO-R-1305, HELCO revised its net SFAS 109 regulatory asset to reflect the recorded balance as of the end of 2006 such that the average test year balance is $26,000 lower. The Consumer Advocate agrees with HELCO's average 2006 test year estimate. Stipulated Settlement Letter, Exhibit 1 at 6.

g. Pension Asset

HELCO's estimate of the average pension asset is $14,143,000 for the 2006 test year. HELCO-R-1601; HELCO-R-904. As reflected in CA-101, Schedule B-1, the Consumer Advocate included the recorded 2006 pension asset balance in rate base which resulted in an average test year rate base adjustment of ($29,000). Although the parties disagree on the criteria to determine when a pension asset should be included in rate base, the Company and the Consumer Advocate agree that the pension asset should be included in HELCO's rate base with an average test year adjustment of ($29,000), such that the average test year balance is $14,143,000, as shown on HELCO-R-1601. Stipulated Settlement Letter, Exhibit 1 at 6-7.

h. OPEB Amount

HELCO's estimate of the average OPEB Amount is $0 for the 2006 test year. HELCO-R-1601; HELCO-R-905. The Consumer Advocate agrees with HELCO's average 2006 test year estimate. Stipulated Settlement Letter, Exhibit 1 at 7.

i. Working Cash

HELCO's estimate of working cash for test year 2006 is $2,460,000 at present rates and ($710,000) at proposed rates. HELCO-R-1606. As shown in footnote b of Schedule B of CA-101, the Consumer Advocate adopted the Company's test year estimate of $2,183,000 for working cash at present rates as shown in HELCO-1606. The Consumer Advocate used a ratio of the Company's change in rate base - working cash to HELCO's proposed increase and applied the ratio to its own proposed increase of $16,643,000 to derive its test year estimate of ($2,204,000) for the change in rate base – working cash. The Company revised its working cash calculations as explained in HELCO RT-16. HELCO and the Consumer Advocate agree on a test year estimate of $2,460,000 for working cash at present rates and ($3,170,000) for change in rate base – working cash, as shown on HELCO-R-1606. Stipulated Settlement Letter, Exhibit 1 at 8.

3. Deductions From Rate Base

a. Introduction

In this case, the following are the sources of funds from non-investors that are deducted from rate base: (1) Unamortized Contributions In Aid Of Construction, (2) Customer Advances, (3) Customer Deposits, (4) Accumulated Deferred Income Taxes, and (5) Unamortized Investment Tax Credits.

b. Unamortized Contributions In Aid Of Construction

HELCO's estimated average Unamortized Contributions in Aid of Construction is $58,431,000 for the 2006 test year. HELCO-R-1601; HELCO-R-1603. The Consumer Advocate and HELCO both used HELCO's December 31, 2005 adjusted balance (HELCO-1604) of $56,925,000 as the beginning of test year balance for CIAC. For the test year ending balance, the Consumer Advocate started with the December 31, 2006 estimated balance of $58,149,000 but replaced the estimated cash receipts and in-kind transfers ($2,975,000) with the 2006 recorded amounts ($4,219,000) provided in response to CA-SIR-51 to derive an end of test year balance of $59,393,000 (as shown in CA-101, Schedule B-2). The Consumer Advocate's average test year balance was $58,159,000. HELCO proposes to use the December 31, 2006 recorded amount of $59,936,000 for all CIAC items (i.e., cash receipts, in-kind receipts, transfer from advances and amortization) for its end of test year balance, as shown in HELCO-R-1603. For purposes of settlement, the Consumer Advocate accepts HELCO's average test year balance of $58,431,000. Stipulated Settlement Letter, Exhibit 1 at 7.

In Schedule B-2, the Consumer Advocate also included a placeholder for post-test year collections of CIAC for 2006 plant additions. The Company opposed the inclusion of an adjustment for post-test year collections of CIAC since the Consumer Advocate's and HELCO's respective average test year balances both already included collections of CIAC as of the end of the test year for post-test year plant additions. The Company further stated that if post-test year collections of CIAC (for test year plant additions) are included as an offset to rate base, collections of CIAC (and customer advances) for post-test year plant additions must be removed from the test year rate base. For purposes of settlement, the Consumer Advocate will not pursue this adjustment in this proceeding. Stipulated Settlement Letter, Exhibit 1 at 7.

c. **Customer Advances**

HELCO's estimated average Customer Advances is $30,189,000 for the 2006 test year. HELCO-R-1601; HELCO-R-1604. The Consumer Advocate and HELCO both used HELCO's December 31, 2005 recorded balance (HELCO-1605) of $28,597,000 as the beginning of test year balance for customer advances. For the test year ending balance, the Consumer Advocate started with the December 31, 2006 estimated balance of $29,254,000 but replaced the estimated receipts ($3,231,000) with 2006 recorded amounts ($6,413,000) provided in HELCO's response to CA-SIR-51 to derive an end of test year balance of $32,436,000 (as shown in CA-101, Schedule B 2). The Consumer Advocate's average test year balance was $30,517,000. HELCO proposes to use the December 31, 2006 recorded amount of $31,780,000 for its end of test year balance, as shown in HELCO-R-1604. For purposes of settlement, the Consumer Advocate accepts HELCO's average test year balance of $30,189,000. The Consumer Advocate will also not pursue an adjustment for post-test year collections of customer advances. Stipulated Settlement Letter, Exhibit 1 at 7.

d. <u>Customer Deposits</u>

HELCO's estimated average Customer Deposits is $930,500 for the 2006 test year. HELCO-R-1601; HELCO-WP-706. The Consumer Advocate agrees with HELCO's average 2006 test year estimate. Stipulated Settlement Letter, Exhibit 1 at 7.

e. <u>Accumulated Deferred Income Taxes</u>

HELCO's estimated average Accumulated Deferred Income Taxes ("ADIT") is $25,870,000 for the 2006 test year. HELCO-R-1601; HELCO-R-1304. In CA-101, Schedule B-3, the Consumer Advocate proposed a number of adjustments to accumulated deferred income taxes. Although the Company does not agree with all of the Consumer Advocate's adjustments, for the purposes of minimizing the issues in this proceeding, the Company and the Consumer Advocate were able to agree on an adjustment of $1,367,000 on an average test year basis, as shown on HELCO-R-1304. Stipulated Settlement Letter, Exhibit 1 at 8.

HELCO and the Consumer Advocate were also able to agree on the deferred tax impact of the Keahole CT-4 and CT-5 write down, as shown on HELCO-RWP-1304c. Stipulated

Settlement Letter, Exhibit 1 at 7.

For purposes of settlement, HELCO and the Consumer Advocate agree on an average test year balance of $25,870,000 for accumulated deferred income taxes, as shown on HELCO-R-1304. Stipulated Settlement Letter, Exhibit 1 at 7.

f. Unamortized Investment Tax Credit

The Company agrees with the Consumer Advocate's proposed adjustment in CA-101, Schedule B-4 to update the unamortized state ITC to an average test year balance of $11,865,000, based on recorded December 31, 2005 and December 31, 2006 amounts, before any adjustments for the Keahole settlement. Stipulated Settlement Letter, Exhibit 1 at 8.

HELCO and the Consumer Advocate were also able to agree on the state ITC impact of the Keahole CT-4 and CT-5 write down, as shown on HELCO-RWP-1303. Stipulated Settlement Letter, Exhibit 1 at 8.

For purposes of settlement, HELCO and the Consumer Advocate agree on an average test year balance of $11,562,000 for unamortized state ITC, as shown on HELCO-R-1303. Stipulated Settlement Letter, Exhibit 1 at 8.

D. RATE OF RETURN

1. Introduction

The following guidelines apply to the determination of a fair rate of return.

> [A] fair return must:
>
> (1) be commensurate with returns on investment in other enterprises having corresponding risks and uncertainties;
>
> (2) provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and
>
> (3) provide a return sufficient to assure confidence in the financial integrity of the enterprise to maintain its credit and capital-attracting ability.

Re Hawaiian Electric Co., Docket No. 7766, Decision and Order No. 14412 (December 11, 1995) ("D&O 14412") at 47; Re Hawaiian Electric Co., Docket No. 7700, Decision and Order No. 13704 (December 28, 1994) ("D&O 13704") at 60-61; Re Hawaiian Electric Co., Docket No. 6998, Decision and Order No. 11699 (June 30, 1992) ("D&O 11699") at 139-40; Re Hawaii Electric Light Co., Docket No. 94-0140, Decision and Order No, 15480 (April 2, 1997) ("D&O 15480") at 31; citing Bluefield Waterworks and Improvement Co. v. Public Service Comm'n, 262 U.S. 679 (1923) and Federal Power Comm'n v. Hope Natural Gas , 320 U.S. 591 (1944). See Re Hawaii Electric Light Co., Docket No. 7764, Decision and Order No. 13762 (February 10, 1995) ("D&O 13762") at 47; Re Hawaii Electric Light Co., Docket No. 6999, Decision and Order No. 11893 (October 2, 1992) ("D&O 11893") at 64; Re Maui Electric Co., Docket No. 97-0346, Amended Decision and Order No. 16922 (April 6, 1999) ('D&O 16922") at 33; Re Maui Electric Co., Docket No. 96-0040, Decision and Order No. 16134 (December 23, 1997) ("D&O 16134") at 16-17; Re Maui Electric Co., Docket No. 94-0345, Decision and Order No. 15544 (April 28, 1997) ("D&O 15544") at 33; Re Maui Electric Co., Docket No. 7000, Decision and Order No. 13429 (August 5, 1994) ("D&O 13429") at 52; Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), Permian Basin Rate Cases, 390 U.S. 747 (1968), Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989).

In order to meet the foregoing criteria, the fair rate of return should at least be equal to HELCO's composite cost of capital, because the composite cost of capital represents the carrying cost of the money received from investors to finance the rate base.

A return on rate base at least equal to HELCO's composite cost of capital would allow HELCO to cover the capital costs of the business; provide a return on investment commensurate with returns on other investments having corresponding risk and provide assurances to the financial community of HELCO's financial integrity. HELCO T-18 at 3-4.

a. Calculation of the Cost of Capital

The aggregate return required by investors is called the "cost of capital". The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (e.g., short-term debt bonds, preferred stock, hybrid securities, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. See HELCO T-18 at 4.

2. Stipulated Cost of Capital

The parties agree on the capitalization for the test year, the costs of short-term debt, long-term debt, taxable debt, and rate of return on common equity. Stipulated Settlement Letter, Exhibit 1 at 8-11.

The appropriate average capital structure for the 2006 test year, including the earnings requirements for the various components, is as follows:

	(A)	(B) Capitalization	(C)	(D)
	Amount (000's)	Percentage of Total	Earnings Requirements	Weighted Earnings Requirements (B) x (C)
Short-Term Debt	$ 49,550	13.24%	5.00%	0.66%
Long-Term Debt	$117,408	31.37%	5.92%	1.86%
Taxable Debt	$ 0	0.00%	6.20%	0.00%
Hybrid Securities	$ 9,152	2.45%	7.50%	0.18%
Preferred Stock	$ 6,563	1.75%	8.37%	0.15%
Common Equity	$191,544	51.19%	10.70%	5.48%
Total	$374,216	100.00%		8.33%

HELCO-R-1801 at 1.

E. COST OF SERVICE/RATE DESIGN

Cost of Service Study/Inter-Class Allocation of Increase

HELCO provided its embedded cost of service study in direct testimony based on a cost classifications methodology previously approved by the Commission. The Consumer Advocate proposed to change the classification of certain distribution costs from customer-related to demand-related costs, and proposed to change the classification of some non-fuel production O&M expenses from a demand to an energy classification. The Company prefers that these classifications remain as the Company originally proposed, which would be consistent with the cost of service methodology that the Company has used and the Commission has approved in prior rate cases. For purposes of settlement, the Consumer Advocate accepts the use of the Company's cost classification methodology explained above for cost of service study purposes in this proceeding. Stipulated Settlement Letter, Exhibit 1 at 10-11.

In direct, HELCO proposed that Schedules R, G and H class revenues increase by 9.25% (which was 100% of the system average increase of 9.25%), Schedules J (10.62%) and F (11.5%) class revenues increase by an above average increase, and Schedule P (6.94%) class revenues increase by a below average increase. The Consumer Advocate proposed that the increase be obtained by use of a proposed "Spread %" set forth in CA-T-5, page 43 that would be used to distribute the Consumer Advocate's recommended sales rate revenue increase, after taking into account the Consumer Advocate's proposed "Power Factor Revision" and "Miscellaneous Charges" revenue increases. Rate Design Stipulated Settlement Letter, Exhibit 1 at 1.

For purposes of settling these issues in this proceeding, HELCO and the Consumer Advocate agree that an allocation of the remaining revenue increase (after reflecting additional revenues due to rule changes) be based on assigning the average overall increase percentage authorized by the Commission to Schedules R, G and H and allocating the remaining revenue increase to the remaining classes in order to gradually move the associated rates of return closer to cost of service as follows:

- System Average Increase (7.55%) to Schedules R, G, and H
- 75% of System Average Increase (5.66%) to Schedule P
- 125% of System Average Increase (9.43%) to Schedule F
- Remaining Increase to Schedule J (8.67%)

Rate Design Stipulated Settlement Letter, Exhibit 1 at 1.

Exhibit 2 to the Rate Design Stipulated Settlement Letter provides the associated cost of service and rates of return by rate class based on the revenue increase approved in Interim Decision and Order No. 23342.

This method of rate increase distribution among classes is similar to what the Company used in its direct and rebuttal testimonies. It takes into consideration the positions of HELCO and the Consumer Advocate to gradually move inter-class revenues toward the estimated class cost of service. Rate Design Stipulated Settlement Letter, Exhibit 1 at 1.

Intra-Class Rate Design

HELCO proposed increases to customer charges for Schedules G, J, H and P; increases in demand charges for Schedule J and P; and energy charge rate increases. Assuming a lower revenue increase than that proposed in HELCO's direct testimony, the Consumer Advocate proposed that the existing structure of customer charges, minimum charges, energy charges, and demand charges within HELCO rate schedules G, J, H, P and F be retained. After accounting for the Commission-approved base fuel energy cost rate as an adjustment to the existing energy rates, the Consumer Advocate recommended that commercial customer charges be increased in proportion to overall percentage revenue changes for each class and that the demand rate elements for Schedules J and P be increased no more than 30% above present rate levels, with all other tariff elements being adjusted uniformly, in equal percentages, to achieve the revenue levels required for the overall rate schedule. Rate Design Stipulated Settlement Letter, Exhibit 1 at 1.

For purposes of this settlement, HELCO and the Consumer Advocate agree to limit commercial customer charge increases as set forth below and limit the Schedule J demand charge to a 29% increase as specified in the Rate Design Stipulated Settlement Letter, Exhibit 1 at 1.

To conform to the revenue increase approved in Interim Decision and Order No. 23342, HELCO and the Consumer Advocate agree to the rates included in HELCO RT-20 with the changes identified in the Rate Design Stipulated Settlement Letter, Exhibit 1, pages 2 through 3. Rate Design Stipulated Settlement Letter, Exhibit 1 at 2.

HELCO proposed in direct testimony to revise the Schedule R minimum bill provision to the higher of $20.00 or the bill calculated based on 15% of the highest kWh usage in the last 11 months (although this revised minimum bill provision would not apply to LIHEAP customers and net energy metering customers). The Consumer Advocate did not agree with HELCO's proposal based on considerations of tariff complexity, ratepayer equity and customer resistance. In addition, the Consumer Advocate maintained that there were alternatives to the revised Schedule R minimum bill that could accomplish the purpose of the revised tariff provision. To minimize the issues in this proceeding, the Company agrees not to revise the Schedule R minimum bill provision in this proceeding. Stipulated Settlement Letter, Exhibit 1 at 11.

At its proposed rate increase level, the Consumer Advocate recommended that the first two energy blocks up to 1,000 kwh/month receive the average percentage revenue increase ordered for the residential class and the third block for usage above 1,000 kwh/month be priced \$0.008741 above the middle block.[3] Rate Design Stipulated Settlement Letter, Exhibit 1 at 4.

In HELCO RT-20, the Company explained that the proposed rates for the three residential energy blocks create meaningful bill impact differences and mitigate the rate impact on the smallest users of the system, as shown in Schedule R bill comparisons in Exhibit 3 of the Rate Design Stipulated Settlement Letter. The Company's position was that the differentiation in bill impact would not be achieved if the same percentage increase applied to both the first and second tier blocks up to 1000 kWh per month. Rate Design Stipulated Settlement Letter, Exhibit 1 at 4.

For purposes of settlement, HELCO and the Consumer Advocate agree on the following non-fuel energy charges for the three residential blocks:

Schedule R non-fuel energy charges:

12.3792 cents per kWh, first 300 kWh

14.4896 cents per kWh, next 700 kWh

15.3203 cents per kWh, over 1000 kWh

Rate Design Stipulated Settlement Letter, Exhibit 1 at 4.

HELCO's rate schedules include an adjustment (either 0.1% or 0.15%) that is applied to the customer's monthly energy and demand charge for each 1% of average monthly power factor above or below 85%. The Consumer Advocate proposes that a 0.1% adjustment be applied to the customer's monthly energy and demand charge for each 1% of average monthly power factor

[3] Although CA-T-6, page 50 (and as a result the Rate Design Stipulated Settlement Letter) specifies an amount of \$0.8741, it is evident from footnote 30 at the bottom of page 50 that the Consumer Advocate meant \$.008741 (i.e., 0.8741 cents) rather than \$.8741.

above or below 95% (CA-T-5 at 79). For purposes of settling these issues in this proceeding, HELCO will accept a Schedule P power factor adjustment of 0.1% that leaves in place the 85% power factor level with credits for power factor above 85% and charges for power factor below 85% and agree to conduct a power factor study for the next HELCO general rate case. Stipulated Settlement Letter, Exhibit 1 at 11.

Revisions to Rate Schedules/Rule Changes

The Company originally proposed to revise the Rider A charges based on the proposed cost of service in this case. The Consumer Advocate proposed to not change the Rider A charges. These charges are also being addressed in Docket No. 2006-0497 (standby service and interconnection tariff proceeding). The Company will accept the Consumer Advocate's proposal and will maintain the Rider A charges at their existing levels. Any changes to the Rider A charges will be addressed in the standby service tariff proceeding. Stipulated Settlement Letter, Exhibit 1 at 11.

HELCO did not propose changes to the non-sales related charges such as the Returned Payment Charge, Field Collection Charge, Service Establishment Charges and Late Payment Charge. The Consumer Advocate proposed that HELCO adopt the increased non-sales related charges that HECO proposed in Docket No. 04-0113. For purposes of settling these issues in this proceeding, HELCO agrees with the Consumer Advocate's proposal to increase the non-sales related charges as reflected in the proposed modifications to Rule No. 7 and Rule No. 8 in HELCO-R-2015. The Consumer Advocate does not object to revising the Returned Check Charge to a Returned Payment Charge. Stipulated Settlement Letter, Exhibit 1 at 11.

Fuel Plan

The Consumer Advocate proposed that HELCO periodically file a "fuel plan" with the

Commission to "prove" that it has taken appropriate actions to acquire fuel at reasonable costs. Rate Design Stipulated Settlement Letter, Exhibit 1 at 5.

HELCO agreed that it should take appropriate action to acquire fuel at reasonable costs, and maintained that HELCO already has taken such action. HELCO's position was that it would be unnecessary to require HELCO to periodically file a fuel plan with the Commission because 1) pricing and supply of the fuel for HELCO are in accordance with the fuel supply contracts specified below, 2) the appropriate time to review the pricing in long-term contracts is when the contracts are approved, and 3) in the case of HELCO's long-term contracts, the fuel supply contract amendments have already been approved by the Commission, and the Consumer Advocate supported such approval. Rate Design Stipulated Settlement Letter, Exhibit 1 at 5.

With respect to the appropriate actions HELCO already takes to acquire fuel at reasonable costs, from time to time, HECO, on behalf of HELCO, negotiates long-term fuel supply contracts with the only two on-island refineries, Chevron Products Company ("Chevron") and Tesoro Hawaii Corporation ("Tesoro"). The Commission must approve these long-term fuel supply contracts. In its application for approval of the fuel supply contracts, HECO and HELCO must demonstrate that it has taken appropriate measures to responsibly and cost-effectively acquire its fuel supplies and related services (liquid petroleum terminalling and inter-island fuel barging, for example) in order to obtain the approval of the Commission. The contracts define, among other things, the formulae for pricing of the fuel. Pricing is tied to widely used industry indices. Rate Design Stipulated Settlement Letter, Exhibit 1 at 5.

HELCO's fuel prices are the result of fuel contracts that have been approved by the Commission. The current inter-island fuel contract, approved by the Commission in Docket No. 97-0396 on December 30, 1997 is the essential contractual basis of the fuel purchase arrangements still in effect. Rate Design Stipulated Settlement Letter, Exhibit 1 at 5.

As stated in the direct testimony of Ms. Giang in HELCO T-4 (page 19), Industrial Fuel Oil ("IFO") and diesel fuel continue to be supplied by Chevron and Tesoro to HELCO under existing fuel supply contracts, which were extended and revised by amendments executed on April 12, 2004 and March 29, 2004, respectively. These fuel supply contract amendments were approved by the Commission in Decision and Order No. 21523 issued on December 30, 2004, in Docket No. 04-0129, and were effective on January 1, 2005, and will be effective for a period of ten years. These contracts and amendments were the result of HECO/HELCO's fuel procurement process that involves commercial negotiating strategies and negotiations on the basis for the pricing of the fuel to be purchased. These contracts and amendments affirm the basis for the pricing of the fuel purchases. Rate Design Stipulated Settlement Letter, Exhibit 1 at 5.

For purposes of the settlement, the Consumer Advocate agrees to withdraw its recommendation to require HELCO to periodically file a fuel plan. Rate Design Stipulated Settlement Letter, Exhibit 1 at 5.

III. KEAHOLE CT-4 AND CT-5

A. KEAHOLE PROJECT COSTS

1. Keahole CT-4 and CT-5

The average depreciated, original cost for CT-4 and CT-5 that was included in HELCO's average rate base for the 2006 test year prior to HELCO's settlement with the Consumer Advocate was $107,280,000. See HELCO-R-1505 at 1, attached as an exhibit to HELCO RT-15. This amount included the average depreciated, original cost ($5,896,000) for the $7.57 million that the Commission allowed to be included in rate base in Docket No. 99-0207 (HELCO's 2000 test year rate case) for the three "Pre-PSD" facilities, based on the

Commission's estimate of the usefulness of these components to support the needs of the existing Keahole generating station prior to the addition of CT-4 and CT-5, as is discussed below. HELCO RT-1 at 11.

Other rate base deductions, in addition to Accumulated Depreciation, are associated with the CT-4 and CT-5 costs, as Lorie Ishii explained in HELCO RT-13. Accumulated deferred income taxes ("ADIT") are deducted from rate base. In addition, the project generated state investment tax credits, and unamortized state investment tax credits ("SITC") are deducted from rate base, as Ms. Ishii explained. As a result, the net impact of CT-4 and CT-5 on HELCO's average rate base for the 2006 test year prior to the settlement was $98,829,000, as shown in HELCO-R-1505 at 1. HELCO RT-1 at 11-12.

As stated below, in resolving the issues between HELCO and the Consumer Advocate with respect to the costs to be included in rate base for CT-4 and CT-5, the Parties agreed to a reduction of $12,898,000 of gross plant in service (or $12,000,000 of plant in service net of accumulated depreciation) associated with the CT-4 and CT-5 units at the Keahole generating station, associated reductions in depreciation expense, accumulated deferred income taxes, unamortized state ITC and amortization of state ITC (the "Keahole adjustment").[4] HELCO RT-1 at 12.

The average depreciated, original cost for CT-4 and CT-5 that is included in HELCO's average rate base for the 2006 test year after the settlement is $95,279,000. See HELCO-R-1505 at 2 (also attached as an exhibit to HELCO RT-15). This amount also includes the average depreciated, original cost ($5,896,000) for the $7.57 million that the Commission allowed to be

[4] The Consumer Advocate's total proposed adjustment in its direct testimonies for the 2006 test year rate base (taking into account a partially offsetting adjustment to accumulated depreciation on Noise Abatement, Landscaping, and Legal costs, but not Rezoning costs) was $22.4 million. See CA-101, Schedules B-7 & B-8; HELCO RT-1 at 16.

included in rate base in Docket No. 99-0207 (HELCO's 2000 test year rate case) for the three "Pre-PSD" facilities. HELCO RT-1 at 12.

The net impact of CT-4 and CT-5 on HELCO's average rate base for the 2006 test year after the settlement is $87,955,000, as shown in HELCO-R-1505 at 2. HELCO RT-1 at 13.

2. Settlement with Consumer Advocate

In Schedules B-7 and B-8 in CA-101, the Consumer Advocate proposed adjustments to remove $24,007,000 associated with the cost of the Keahole CT-4 and CT-5 generating units from plant in service (and to remove the associated accumulated depreciation of $1,634,000) on an average test year basis. HELCO's position was that there should be no adjustments to the CT-4 and CT-5 plant in service amounts.

For the purposes of reaching a settlement, HELCO and the Consumer Advocate agreed to an adjustment of $12,898,000 of gross plant in service, less $898,000 of average accumulated depreciation for 2006 (i.e., $12,000,000 of plant in service net of average accumulated depreciation) associated with the cost of the CT-4 and CT-5 units at the Keahole generating station. See Agreements Reached Between HELCO and the Consumer Advocate, attached as Exhibit 1 to HELCO's Stipulated Settlement Letter, Docket No. 05-0315, filed April 5, 2007, at 5.

Agreeing to write down $12.9 million of gross plant investment for the Keahole CT-4 and CT-5 generating units was a very difficult decision to make. The Company had to immediately write down the $12.9 million of gross plant investment. A write down of that magnitude substantially impacted consolidated earnings for the three Hawaiian Electric utilities for the first quarter of 2007. The Company is obviously concerned with how investors will perceive this occurrence and whether there will be any lasting impacts from an investment standpoint. HELCO RT-1 at 8.

As reflected in its direct testimonies, the Company's position was that the entire $117 million of gross plant investment for the Keahole CT-4 and CT-5 project should be included in rate base. However, the issue of rate base inclusion of the Keahole CT-4/CT-5 investments was highly contentious, with the Consumer Advocate and especially KDC taking very aggressive positions in this proceeding on excluding significant amounts of this investment from the Company's rate base. HELCO RT-1 at 8-9.

Although the Company felt comfortable with the strength of its case, it also recognized that due to a great number of reasons and the passage of approximately fifteen years from the inception of the project, the Keahole CT 4/CT-5 project costs had grown significantly from the original cost estimate. HELCO RT-1 at 9.

HELCO also recognized that it would be to no one's interest to prosecute this rate case to its conclusion without settlement. Rate cases are inherently a resource drain. The Company's witnesses and support people had worked intensively on this rate case for ten months with little break, in addition to trying to keep up with their regular job functions. An evidentiary hearing on the full case would have involved the appearance of a maximum of 33 witnesses for HELCO, testifying on 54 direct, supplemental and rebuttal testimonies. The preparation effort would have been enormous. The large number of witnesses and testimonies was due in large part to the complexity of the Keahole issues. The Company found it necessary to introduce nine additional Keahole witnesses on rebuttal. HELCO RT-1 at 9.

Decision making on each Keahole issue would have been a difficult and arduous task. It would have required a full understanding and unraveling of the history of a project that spanned 15 years and involved law suits and land use and air permitting proceedings in addition to dockets at the Commission. Realistically, such a process would have taken time and potentially delayed timely decision making on the entire rate case. HELCO RT-1 at 9.

During settlement discussions, it became clear that the Consumer Advocate would not agree to a global settlement of the revenue requirement issues without a significant write down of the Keahole investment. Settlement discussions began on or about March 7, 2007 and continued through March 21, 2007 when the parties agreed on a global settlement. The parties exchanged proposals and counter-proposals during this period. On March 21, 2007, the Consumer Advocate provided a global settlement counter proposal, indicating it would not be willing to negotiate any further on the terms and that rejection would mean collapse of any chance of a global settlement. HELCO decided that all things considered, it would be best to accept the settlement, bring closure to the Keahole matter and allow HELCO to focus its attention on meeting the challenges of the future and providing efficient, reliable service to its customers. See HELCO RT-1 at 8-10.

3. Definition of Keahole Project

The term "Keahole Project" generally refers to the phased installation of a nominal 58 megawatt ("MW") (gross) dual-train combined cycle ("DTCC") generating unit at HELCO's existing Keahole generating station site, consisting of (1) two 20 MW simple-cycle combustion turbines ("CTs"), CT-4 and CT-5, (2) two heat recovery steam generators ("HRSGs"), (3) an 18 MW (gross) steam turbine generator ("STG"), ST-7, and (4) auxiliary equipment. The installation of the HRSGs and the steam turbine generator were deferred due to HELCO's power purchase agreement ("PPA") with Encogen Hawaii, L.P. ("Encogen" a partnership of Enserch Development Corporation "Enserch" and Jones Capital Corp. whose successor in interest is Hamakua Energy Partners, L.P., or "HEP"), and ST-7 is now on track to be in service in 2009.

HELCO's application to commit funds for the CT-4 project was the subject of Docket No. 7048, while the remaining CT, HRSGs, and STG were the subject of Docket No. 7623. See HELCO RT-1 at 15. HELCO has installed CT-4 and CT-5 at the Keahole generating station site. HELCO RT-9B at 3.

4. Brief Project History

The Keahole Project background and permitting history are summarized in Appendix C to the Keahole Cost Report, and details of the related administrative agency and court proceedings were included in the status reports filed monthly beginning in October 1995 in Docket No. 7623 ("Monthly Status Reports").

Based on its capacity planning criteria, the Company initially determined the need for additional increments of capacity in 1994-1995 (20 MW), 1996 (20 MW) and 1997 (18 MW) due to forecast load growth and planned retirements of older generating units.[5] HELCO explored a number of possible alternatives for the first 20 MW increment of capacity, but HELCO determined, and the Commission agreed, that CT-4 was the only alternative with the possibility of fruition in the 1994-1995 timeframe.[6]

The Company's application for CT-4 was filed with the Commission in July 1991 and was amended in September 1992 to reflect a change in siting to the Keahole site.[7] Given the urgency of the need, HELCO acted expeditiously to obtain the needed permits and equipment for CT-4.

The Commission approved the commitment of funds associated with installation of CT-4 and CT-5 in Decision and Order No. 13050 ("D&O 13050") issued January 21, 1994 in Docket No. 7048 and in Decision and Order No. 14284 ("D&O 14284") issued September 22, 1995 in

[5] HELCO-1501, Appendix C at 2.
[6] D&O 13050 at 8.
[7] HELCO-1501, Appendix C at 3.

Docket No. 7623, which includes certain conditions.

The application for an amendment to the Company's Keahole Conservation District Use Permit ("CDUP") was filed with the Department of Land and Natural Resources ("DLNR") in August 1992. The application for the air permit was filed with the Department of Health ("DOH") in January 1993. In addition, a letter of intent for the purchase of the CT was sent on October 31, 1991 (subject to cancellation without penalty before June 1, 1992).[8]

In 1994, HELCO requested permission to initiate work on the project prior to receiving a Prevention of Significant Deterioration ("PSD") permit. The DOH and the U.S. Environmental Protection Agency ("EPA") approved in writing HELCO's proposed Pre-PSD permitting and installation activities. HELCO then commenced Pre-PSD work before receipt of the PSD permit in order to shorten the time to install CT-4 and CT-5 once the PSD permit was received.

HELCO anticipated that there would be opposition to siting additional generation at Keahole, however, the degree of opposition experienced with respect to CT-4 and CT-5 was unexpected. Despite HELCO's expeditious application for Keahole-related permits in the 1991-1993 timeframe, the unexpected degree of opposition, along with other unforeseeable events beyond the Company's control, gave rise to legal and permitting complications that substantially delayed the Project's completion, as discussed in greater detail below.

Following a favorable Hawaii Supreme Court ruling, HELCO reached a negotiated settlement with project opponents in 2003, and the project was able to be completed. See HELCO RT-1 at 48-49. CT-4 and CT-5 were installed and were put into limited commercial operation in May and June 2004, respectively. See HELCO RT-1 at 50-51.

The costs for CT-4 and CT-5 were reported to the Commission in the Keahole CT-4 and

[8] Id.

CT-5 Cost Report ("Keahole Cost Report"), which was filed with the Commission on September 7, 2005.[9] A copy of the Keahole Cost Report was provided as HELCO-1501. HELCO RT-15 at 1-2. The major systems, machinery and structures that are included in the CT-4 and CT-5 generating unit projects are described in Appendix A to the Keahole Cost Report.

The Keahole Cost Report included actual costs through June 30, 2005 and outstanding costs to complete CT-4 and CT-5, as explained in Exhibit V of the report. Updates and revisions to CT-4 and CT-5 costs were provided and explained in HELCO T-15, HELCO RT-15, and the exhibits thereto. HELCO-R-1505 shows the average depreciated original cost for CT-4 and CT-5 that is included in HELCO's average rate base for the 2006 test year and the net impact of CT-4 and CT-5 on HELCO's average rate base for the 2006 test year considering accumulated depreciation, ADIT, and SITC for CT-4 and CT-5, both before and after the settlement with the Consumer Advocate.[10] See HELCO RT-1.

B. URGENT NEED FOR ADDITIONAL GENERATION ON THE ISLAND OF HAWAII

1. Introduction

The Consumer Advocate did not raise any issue regarding the need for CT-4 or CT-5. In CA-T-3, Mr. Carver stated:

> Q. In this proceeding, is the Consumer Advocate contesting HELCO's decision to add generation in West Hawaii or any asserted need to add generation capacity in order to meet growing demand for electricity?
>
> A. No.

[9] CT-4 became commercially available on May 25, 2004, and CT-5 became commercially available on June 30, 2004, but HELCO was required to install noise mitigation equipment before beginning full-time operation of CT-4 and CT-5. HELCO informed the Commission of the status of CT-4 and CT-5, respectively, in the June 7, 2004 and July 2, 2004 CT-5/ST-7 Monthly Status Reports. As a result of extensions agreed to by the parties in Docket Nos. 7048 and 7623, and approved by the Commission, HELCO was allowed to file its cost reports for CT-4 and CT-5 after the installation of the noise mitigation equipment was completed. As noted above, the cost report was filed on September 7, 2005.

[10] These offsetting impacts were provided to Mr. Fong by other witnesses, including Ms. Deorna Ikeda, HELCO RT-12, and Ms. Lorie Ishii, HELCO RT-13. HELCO RT-15 at 5.

CA-T-3 at 51, lines 4-9; HELCO RT-4 at 16.

KDC did not contest the need for CT-4, but suggested that CT-5 might not be needed.[11] KDC, however, did not present any evidence in support of such a position, and left the matter to the Commission to decide.[12] In contrast, the record evidence fully supports the need for CT-5 at the time HELCO commenced the expenditures necessary to be able to permit and install CT-5, as well as at the present time.

In HELCO RT-4A, Mr. Dizon summarized the original determination of need for CT-4 and CT-5, HELCO's efforts to expedite installation of CT-4 and CT-5 in light of the urgency of HELCO's generating situation, alternatives considered by HELCO, HELCO's successful efforts to proceed in parallel with the negotiation of a PPA with Encogen, while diligently pursuing the installation of CT-4 and CT-5 in order to meet HELCO's growing need for firm capacity, as well

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[11] KDC asserted in its Position Statement, dated February 18, 2007, that "KDC objects to [the] cost of CT-5 and its related facilities to the extent that CT-5 is not used and useful for utility purposes." KDC Position Statement at 1. KDC claimed on page 2 that CT-5 represented "unnecessary capacity," contending that HELCO "[a]dded CT-5 to the Station even though there was no evidence that CT-5's additional capacity was or is warranted or that CT-5 would be or is used or useful."

[12] In HELCO/KDC-IR-125, HELCO requested the following information with respect to KDC's position that: "To the extent that the Commission concludes that CT-5's capacity is not needed and that CT-5 is not used or useful for utility purposes, the Commission should exclude all amounts relating to CT-5 ($50,181.116) from the Company's rate base."

a. In KDC's estimation, is CT-5 'used and useful for utility purposes'?

b. If the response to a. is other than an unqualified 'yes', please provide a specific explanation and documentation to support your position.

c. Is it KDC's position that CT-5 at Keahole is not currently providing benefits to the HELCO system? Please explain and provide documented support for KDC's position.

KDC responded that:

a. KDC has left that determination to the Commission as the Commission stated in Order 14284, Docket No. 7623.

b. KDC has left that determination to the Commission as the Commission stated in Order 14284, Docket No. 7623.

c. KDC has left that determination to the Commission as the Commission stated in Order 14284, Docket No. 7623.

Thus, KDC explicitly left the matter to the Commission to determine.

as HELCO's successful efforts to maintain service to its customers during the extended period that it took to add new generation. His testimony basically summarized testimony and information that had been provided to the Commission in earlier dockets. In HELCO RT-4, Ms. Giang rebutted KDC's claim that CT-5 may not be needed at this time. HELCO RT-1 at 18, 23.

2. Need for CT-4 and CT-5

HELCO's efforts to install CT-4 and CT-5 began in 1991, when HELCO determined that there would be a need to install the next increment of new generating capacity after the installation of Combustion Turbine No. 3 ("CT-3") at Puna.[13] HELCO RT-4A at 2. The need for new generation was considered to be urgent, given HELCO's determination that CT-4 was needed in 1994. See HELCO RT-1 at 25.

The drivers for this new installment of generating capacity included supporting system load requirements by having capacity installed on the west side of the Big Island, and allowing for the retirement of aging existing generators on the HELCO system. Based on HELCO's capacity planning criteria, it was initially determined that HELCO needed additional increments of capacity in 1994-1995 (20 MW), 1996 (20 MW) and 1997 (18 MW) due to forecast load growth and planned retirements of older generating units (as well as other considerations). See HELCO RT-1 at 22-23; HELCO RT-4A at 2-3.

The Commission recognized HELCO's need for additional capacity in the 1994-1995 timeframe, and thus there was no issue in Docket No. 7048 regarding HELCO's need for

[13] In the May 1991 Hawaii Electric Light Company Unit Type and Size Study, HELCO identified the need for additional generation in the April 1994 time frame. This need was based on meeting HELCO's generation planning criteria given the anticipated load growth projected in the May 16, 1990 sales and peak load forecast, and the retirement of existing units upon reaching their expected service lives. The need for additional generation in 1994 also took into account the benefits of increasing HELCO's generation reserve margin to improve HELCO's generation reliability, uncertainties regarding the continued availability of firm capacity from non-utility generators ("NUGs") and limits on the near-term potential peak load savings from demand-side management programs. See HELCO RT-4A at 3.

capacity. Rather, the Commission noted that: "All parties agree that HELCO requires additional capacity to meet its future load requirements. The Consumer Advocate agrees with HELCO that there is an immediate need for additional generation in West Hawaii." D&O 13050 at 3.

HELCO explored a number of possible alternatives in Docket No. 7048 for the first 20 MW increment of capacity, including DSM programs. See HELCO RT-4A at 4. However, the Commission agreed with HELCO that DSM programs could not defer the need for additional capacity, explaining that: "Despite HELCO's efforts to encourage DSM programs, the programs will not eliminate or shift sufficient load to obviate the need for additional generation. They will not be sufficient to reduce enough load in the near term to defer HELCO's proposed unit addition in 1994." D&O 13050 at 8.

Accordingly, the Commission concluded in D&O 13050 that HELCO required additional generation in the West Hawaii area in the 1994-1995 time frame, that none of the parties to the docket disputed the need for capacity, and that "CT-4 is the only alternative with the possibility of fruition in the 1994-1995 timeframe." D&O 13050 at 8. In addition, the Commission found that "HELCO's proposed project is reasonable and in the public interest." D&O 13050 at 14; see HELCO RT-1 at 23; HELCO RT-4A at 4-5.

The Commission also recognized the need for generation in addition to that to be provided by CT-4 in Docket No. 7048 when it explained that the CT-4 project was designed to include facilities and equipment to facilitate the possible future incorporation of CT-4 into a 56 MW DTCC unit. The Commission concluded that "it is prudent and reasonable for HELCO to include in the CT-4 project some of the costs needed to upgrade CT-4." D&O 13050 at 13. The Commission also determined that "the need for additional capacity on the Big Island is such that HELCO must continue parallel planning for additional generation in the event that non-utility generators do not deliver energy as promised. Should it become necessary for HELCO to build CT-5, the provisions made in CT-4 for conversion will help expedite the installation of CT-5." D&O 13050 at 14; see HELCO RT-1 at 24.

HELCO initially determined that CT-5 would be needed in 1996 (and that ST-7 would be needed in 1997). However, HELCO had to accelerate the installation date for CT-5 as part of a contingency plan to address the delays and problems experienced by Puna Geothermal Venture ("PGV") from 1991 to 1993 in adding its 25 MW of committed power, and the uncertainties associated with the continued supply of power by the sugar companies providing firm capacity to HELCO, including Hamakua Sugar Company ("Hamakua") (10 MW)[14] and Hilo Coast Processing Company ("HCPC") (18 MW). HELCO RT-1 at 24-25.

HELCO filed its application for the approval of CT-5 and ST-7 in the CT-5/ST-7 docket, Docket No. 7623 on February 26, 1993. The Commission issued its final decision in the CT-5/ST-7 docket on September 22, 1995 in D&O 14284. In D&O 14284, the Commission concurred that HELCO requires plant additions (beyond the capacity to be provided by CT-4) in the "reasonably near future", and that CT-5 and ST-7 were the appropriate type and size generating units for HELCO to meet its probable future requirements. D&O 14284 at 6; see HELCO RT-1 at 25.

3. Urgency of Need

CT-4's original need date was determined based on the assumption that the 25 MW committed by PGV would be available. However, PGV's project was substantially delayed, which increased the urgency of adding CT-4. PGV's capacity finally became available on a firm

[14] As was addressed in Docket No. 7623, HELCO accelerated the scheduled installation date for CT-5 based on the "HELCO Contingency Plan Analysis", dated February 19, 1993, which examined the impact of the inability of PGV to meet its commitment date for the provision of 25 MW of firm capacity, and the apparent inability of Hamakua to continue to provide firm capacity to HELCO. HELCO RT-1 at 36-37.

basis at the end of June 1993, but other independent power producers ("IPPs") were having financial difficulties and their continued availability was in substantial doubt. In addition, load was continuing to grow on HELCO's system. See HELCO RT-1 at 25-26; HELCO RT-4A at 5.

In Docket No. 7049, the Commission explicitly recognized the urgency of addressing the generation situation and proceeding with CT-4. For example, one of the questions at the conclusion of the evidentiary hearings in Docket No. 7049 in July 1992 was what actions HELCO could take to accelerate the installation of CT-4. HELCO RT-4A at 5. HELCO identified doing Pre-PSD work as an important strategy to accelerate CT-4's installation, and did so in 1992. HELCO RT-1 at 26.

As was addressed in Docket No. 7623, HELCO also accelerated the scheduled installation date for CT-5, based on the "HELCO Contingency Plan Analysis", dated February 19, 1993, which examined the impact of the inability of PGV to meet its commitment date for the provision of 25 MW of firm capacity, and the apparent inability of Hamakua to continue to provide firm capacity to HELCO. See HELCO RT-1 at 36-37.

It is appropriate to consider uncertainties with respect to when firm capacity from IPPs can be installed when determining the timing of a utility's own generation additions. This is so even though such uncertainties are not explicitly considered in the generation planning criteria. The Commission has recognized that the timing of generation additions cannot be determined solely through application of the generation planning criteria, because the criteria do not consider a number of factors. The Commission's decision in Docket No. 7623 recognized the need to consider factors other than those explicitly considered in the generation planning criteria, such as power purchase uncertainties in generation planning, and specifically noted the problems associated with HELCO's power purchases from NUGs, including Hamakua, HCPC and PGV.

Decision and Order No. 14282, filed September 22, 1995 at 8-9. The Commission also recognized in Docket No. 6643, in which it approved HELCO's commitment of funds for CT-3, that unit need may be based on uncertainty with respect to the addition of Qualifying Facility ("QF") capacity (in that case, PGV), as well as application of the generation capacity expansion criteria. See Decision and Order No. 11556, filed March 23, 1992 at 5-6; HELCO RT-4A at 28.

HELCO also was encouraged to maximize its opportunities to install generation as soon as possible. The Commission stated on numerous occasions that, under the circumstances, "HELCO must obviously maximize, rather than minimize, its strategies to meet the demand for additional capacity." See, e.g., Decision and Order No. 14030, Docket No. 7956, filed July 31, 1995 ("D&O 14030") at 25. In Order No. 14502, issued January 26, 1996 in Docket No. 7956 ("Order 14502") the Commission reiterated that: "HELCO's critical need for additional capacity to meet its load requirements is unquestioned, and clearly, the primary consideration is to have the next generation unit on line as quickly as possible." Order 14502 at 4; see also Decision and Order No. 15053 (October 4, 1996), Docket No. 94-0079, at 31; HELCO RT-1 at 31-32.

4. Efforts to Expedite Installation

Given the urgency of the need for additional generation, HELCO acted expeditiously to request the needed approvals and permits for the construction of CT-4 and CT-5: (1) The Commission application for the commitment of expenditures for CT-4 was filed in July 1991 (and was amended in September 1992 to reflect the change to the Keahole site); (2) The CDUA application was filed with the DLNR in August 1992; (3) The application for the air permit was filed with the DOH in January 1993; and (4) The Commission application for the commitment of expenditures for CT-5 was filed in February 1993. See HELCO RT-4A at 6, 25.

In addition to HELCO's permitting efforts, HELCO also sought to expedite the completion of the Keahole Project through its construction management efforts by: (1) ordering long lead-time components (by submitting letters of intent for the purchase of CT-4 and CT-5 on October 31, 1991 and February 1, 1993, respectively); (2) engaging in Pre-PSD construction activities prior to the receipt of its PSD Permit; and (3) addressing construction delays by implementing an accelerated construction schedule.

a. <u>Purchase of the Combustion Turbines</u>

i. <u>CT-4</u>

Due to the long lead time for the combustion turbine generator, HELCO elected to exercise an option for the procurement of the CT-4 generating unit from the equipment packager. This option existed during the procurement process for the CT-3 unit and the Maalaea 14 and 16 units at MECO. The Commission was notified of this decision via letter dated November 20, 1991 in Docket No. 7048. In addition to the combustion turbine, Stone & Webster Engineering Corporation began design and procurement processes for the balance of plant equipment. HELCO RT-4A at 6.

The Company would prefer to have all permits and approvals in hand before placing equipment orders. However, that is not a requirement under General Order No. 7 ("GO 7") project reviews, as Ms. Nanbu explained in HELCO RT-9A. Installation of the generating unit cannot begin until it is on site, and waiting to place orders for long lead time items until all permits have been received can result in substantial delays in completing a time-critical project, because the order date determines the purchaser's place in the manufacturing queue, and it also takes time to manufacture and ship major generating unit components. Such a requirement could preclude the Company from meeting its obligation to serve under circumstances where project reviews exceed the intended 90 days (which is almost always the case for major projects).

HELCO RT-1 at 35; HELCO RT-4A at 6-7.

ii. CT-5

HELCO "committed" to the purchase of the combustion turbine for CT-5 by letter dated May 7, 1993 ("Notice to Proceed"). Issuing the Notice to Proceed enabled HELCO to (1) ensure that the CT-5 unit would be available for installation in accordance with HELCO's schedule, (2) avoid a price increase on the CT-5 engine, and (3) reduce shipping and handling costs by shipping both CT-4 and CT-5 at the same time. As a result, HELCO determined that, on a net present value basis, there was no economic penalty to adding CT-5 in 1995 instead of delaying the addition to 1996. HELCO RT-1 at 36.

As was addressed in Docket No. 7623, HELCO accelerated the scheduled installation date for CT-5 based on the "HELCO Contingency Plan Analysis", dated February 19, 1993, which examined the impact of the inability of PGV to meet its commitment date for the provision of 25 MW of firm capacity, and the apparent inability of Hamakua to continue to provide firm capacity to HELCO. See HELCO RT-1 at 36-37.

As discussed above, prior to issuing the Notice to Proceed in May 1993, HELCO reviewed (1) the status of PGV, Hamakua, and HCPC, (2) the benefits of proceeding with the retirements of its older, less efficient generating units, and (3) the benefits and economics of adding CT-5 in 1995 (even if it were not required on the basis of HELCO's capacity planning criteria until 1996). At that time, PGV still had not demonstrated that it would be able to solve its problems or that it would be able to meet its firm power commitment to HELCO. HELCO also was faced with significant uncertainty regarding the ability of its existing firm capacity producers, Hamakua (whose discontinuance of operations after the fall of 1994 appeared relatively certain) and HCPC (whose status beyond the Fall of 1994 was also uncertain), to continue to meet their firm power commitments. See HELCO RT-1 at 37.

b. Pre-PSD Work

i. Background

The term "Pre-PSD construction" refers to construction activities that are authorized to be done before the effective date of a PSD permit. Pre-PSD construction activities are those that serve as improvements to existing power plant operations and are not directly or solely associated with the emissions unit being permitted. See HELCO RT-15C at 1.

As addressed by Mr. Barry Nakamoto[15] in other dockets, after HELCO had to return to its existing Keahole site, HELCO incorporated plans to start work on certain Pre-PSD facilities before receipt of the PSD air permit, if necessary, in order to shorten the time required to complete the installation of the new generating units after the PSD permit was received. HELCO RT-4A at 9; HELCO RT-9B at 4-5.

The Pre-PSD common facilities that were constructed at Keahole (the "Pre-PSD Facilities") included the Warehouse/Shop building (completed in December 1998), the upgrades to the plant fire protection system (completed in September 1999), and the water treatment system upgrades for Keahole CT-2 (completed in December 1999). They were designed to support the needs of HELCO's planned generating unit additions at Keahole, as well as the needs of the then-existing generating units (CT-2 and six diesel units) and the Keahole generating station. See HELCO RT-4A at 9; HELCO RT-15C at 1-2.

If the PSD air permit was received on a timely basis, the construction of these facilities was expected to start and finish at the same time as CT-4 and CT-5. However, as HELCO noted

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[15] Barry Nakamoto rebutted KDC's contentions regarding the Pre-PSD work done by HELCO, and generally summarized his testimony from HELCO's 2000 test year rate case on this point in HELCO RT-15C. Mr. Nakamoto was the Keahole Project Manager during the Pre-PSD construction period project. See HELCO RT-15C at 1.

in Docket No. 7049 in 1992, and in Docket Nos. 7048 and 7623, HELCO anticipated that work on the Pre-PSD facilities could begin before receipt of the PSD permit if (as actually occurred) the PSD permit was delayed. Expediting the ultimate installation of new generation at Keahole was not the only reason for installing the Pre-PSD Facilities as soon as possible. Rather, maintaining reliable service from HELCO's existing generation at Keahole became an all the more important goal given the delays in adding CT-4 and CT-5 at Keahole, and the key role HELCO's Keahole generation plays in maintaining voltage support and frequency control on HELCO's system. See HELCO RT-4A at 9-10.

In its Position Statement, KDC characterized the Pre-PSD construction at Keahole as a "scheme devised by HELCO" at substantial expense. KDC Position Statement at 11, 21. Contrary to KDC's characterization, it was reasonable for the Company to proceed with Pre-PSD work. Pre-PSD construction is a recognized practice under the EPA's rules to minimize construction time after receipt of an air permit. It is a common practice nationally and had been successfully utilized on other HELCO and MECO projects. The most notable example of HELCO's customers benefiting in the past from Pre-PSD construction is that by doing Pre-PSD work for CT-3, HELCO was able to install CT-3 and have it operational in July 1992, which averted the need for further rolling blackouts on HELCO's system. See HELCO RT-15C at 2-3; see also HELCO RT-9B at 5.

The Pre-PSD work contemplated by HELCO at Keahole was the same type of Pre-PSD work that was performed by HELCO and MECO on earlier generating units under previous DOH and EPA approvals. Warehouse facilities and water treatment upgrades were installed as allowable Pre-PSD construction in conjunction with HELCO's CT-3 project and MECO's Maalaea DTCC No. 1 and M17 projects. Fire protection upgrades were also allowed as Pre-

PSD work in conjunction with HELCO's CT-3 project and MECO's Maalaea DTCC No. 1 project. See HELCO RT-4A at 9; HELCO RT-15C at 2-3; see also HELCO RT-9B at 5; response to CA-IR-504.

As indicated in Mr. Nakamoto's testimony, HELCO followed the same process to obtain approval to do Pre-PSD work for CT-3 at HELCO's Puna Power Plant, and for M17 at MECO's Maalaea Power Plant, as was followed to obtain approval of the Pre-PSD improvements at the Keahole Power Plant. In particular, HELCO used EPA's guidance documents to determine which improvements were permissible as part of Pre-PSD construction.[16] HELCO did not rely solely on its own interpretation of the rules, but rather sought and received approval from EPA and DOH.

ii. Benefits of Constructing the Pre-PSD-Facilities

Commencing Pre-PSD work was part of HELCO's strategy to install new generation as quickly as possible. Given the urgency of the need for CT-4 and CT-5, HELCO commenced Pre-PSD work when it experienced delays in obtaining the PSD permit for CT-4 and CT-5. HELCO RT-15C at 3.

Contrary to KDC's claim that the Pre-PSD construction resulted in "nothing except predictable delays",[17] the completion of the Pre-PSD construction benefited the Keahole Project by shortening the time required to install CT-4 and CT-5 once the final PSD permit was received, and thereby allowing the CT-4 and CT-5 projects to be completed sooner than they would have been if the Pre-PSD items had not been completed prior to the permit's receipt. See

[16] EPA has defined "begin actual construction" in its rules. In addition to its rules, EPA has guidance documents that explain what construction can begin before the issuance of a PSD permit. HELCO followed this guidance in requesting regulatory approval of its Pre-PSD construction. See HELCO RT-15C at 2.

[17] KDC Position Statement at 12.

HELCO RT-15C at 3, 6.

All three of the Pre-PSD common facilities were placed into service and were used and useful, and were providing benefit to the existing plant operations, well in advance of the receipt of the PSD permit. As stated above, the shop/warehouse building was completed in December 1998, the upgrades to the fire protection system were completed in September 1999, and the upgrades to the water treatment system were completed in December 1999. (The PSD permit became final in November 2001.) See HELCO RT-15C at 3-4.

By completing Pre-PSD construction in 1999, HELCO's customers received the benefits of more reliable operations from the Keahole Plant approximately five years sooner than if HELCO had not performed Pre-PSD construction. The completion of the Pre-PSD work also reduced the amount of post-PSD construction required by approximately 6 months. HELCO RT-15C at 4.

iii. DOH and EPA Notices of Violation

KDC also contended that the strategy of including Pre-PSD work led to the issuance of "predictable stop work orders [by] Federal and State officials . . . ." See KDC Position Statement at 21 (emphasis in original). The "stop work orders" referred to by KDC were notices and findings of violation ("NOV") received from the DOH on July 27, 1998, and the EPA on September 14, 1998. The NOVs essentially notified HELCO that the agencies had determined that certain construction activities that HELCO had begun during the Pre-PSD construction phase were not allowed. See HELCO RT-15C at 5.

Neither of the NOVs associated with the Pre-PSD construction were predictable. As shown above, HELCO sought and obtained letters of authorization to confirm its understanding of permissible Pre-PSD construction activities before commencing construction.[18] Such letters are the only means available to obtain advance authorization of Pre-PSD construction. See HELCO RT-15C at 2-3; see also HELCO RT-9B at 5.

While the enforcement actions taken by DOH and EPA delayed completion of the Pre-PSD construction, they did not delay the completion of the CT-4 and CT-5 projects. After the NOVs were issued in 1998, DOH and EPA again reviewed the scope of the Pre-PSD construction work requested by HELCO. DOH visited the site to review the work, and both DOH and EPA reviewed detailed engineering drawings for the work. Based on their review, the agencies approved continued Pre-PSD construction with a revised scope of work. HELCO RT-15C at 5-6.

c. Accelerated Construction Schedule

In November 2002, the Third Circuit Court ("Third Circuit") issued a "stop work" order such that no further installation or construction activity at Keahole on CT-4 or CT-5 could continue. On November 12, 2003, the Third Circuit vacated the stop work order following its acceptance of a settlement agreement between HELCO, KDC, the Department of Hawaiian Homelands ("DHHL"), and other stakeholders. This settlement agreement was reached through a mediation process that helped solve the complicated legal disputes surrounding Keahole. Work to install CT-4 and CT-5 resumed shortly after the stop work order was vacated. HELCO RT-4 at 27.

As stated in the Keahole Cost Report, when construction of CT-4 and CT-5 was allowed to resume in November 2003, HELCO decided to accelerate construction activities in order to

[18] By letter dated May 31, 1994, HELCO requested approval from the DOH and EPA to proceed with construction of the Pre-PSD Facilities (i.e., the fire protection system upgrades, the shop/warehouse, the water treatment system, and switchyard). HELCO's request was approved by DOH on July 13, 1994 and by EPA on August 17, 1994. Pre-PSD construction was initiated in 1997. See HELCO RT-15C at 5.

complete the installation of the major equipment by the end of 2004. HELCO's objective was to install CT-4 and CT-5 as expeditiously as possible to facilitate operating its system with adequate generation capacity and minimize the risk of generation shortfalls. See HELCO RT-4 at 28; HELCO RT-15E at 2-3.

Within a few weeks of resuming construction on November 17, 2003, HELCO had three of its five prime project contractors, along with its construction management team, on-site. On December 1, 2003, Isemoto Contracting was fully engaged in construction, pouring a concrete foundation for a fuel day-tank. Within a few months of resuming construction, HELCO was able to start-up CT-4 (first fires in March 2004) and CT-5 (first fires in June 2004). See HELCO RT-15E at 5.

The following are the dates of the key milestones for CT-4 and CT-5, relating to start-up testing and achieving commercial operation status:

CT-4 first fire date: March 18, 2004
CT-4 first synchronized to grid: March 22, 2004
CT-4 first reached full-load: March 26, 2004
CT-4 declared commercially operable: May 25, 2004
CT-5 first fire date: June 1, 2004
CT-5 first synchronized to grid: June 2, 2004
CT-5 first reached full-load: June 7, 2004
CT-5 declared commercially operable: June 30, 2004

HELCO RT-15E at 6.

It was beneficial for HELCO to accelerate the installation of CT-4 and CT-5 and to complete it as soon as practicable in order to avoid (1) additional delays from potential legal actions by Waimana or other opponents of the project and (2) incurring additional capacity payment costs from HCPC. See HELCO RT-4 at 29; HELCO RT-15E at 4.

When the CT-4 and CT-5 project was halted in 2002, with numerous court proceedings with project opponents pending and unresolved, it was approximately 85% complete. Therefore, once construction was allowed to resume, it was prudent to complete the remaining 15% of the work without delay, and both CT-4 and CT-5 became operational within approximately six months. See HELCO RT-4 at 27; HELCO RT-15E at 3, 5.

HELCO also accelerated construction of CT-4 and CT-5 in early 2004 to provide reasonable assurance that CT-4 and CT-5 could be completed or substantially completed by May 30, 2004, which was the deadline to issue HCPC a written notice for termination of its PPA on January 1, 2005. HELCO issued the written notice of termination to HCPC on May 27, 2004. By that date, CT-4 was commercially operable and HELCO had reasonable assurance that CT-5 would be in commercial operation within a few weeks. With the written notice, the HCPC PPA was terminated on January 1, 2005. The capacity from HCPC was not needed at that point and $5,082,000 in annual capacity payments to HCPC were avoided. See HELCO RT-4 at 29; HELCO RT-15E at 2.

CT-5 was first fired up for testing on June 1, 2004. It was synchronized to the grid on June 2, 2004. It reached full load on June 7, 2004. It was declared in commercial operation on June 30, 2004. HELCO RT-4 at 29.

HELCO had a construction strategy for dealing with the urgency to complete construction and the frequent construction stoppages. As early as 1998, when HELCO's construction at Keahole was first interrupted, HELCO made preparations to be in a "ready stand-by" mode to resume and complete construction as soon as the necessary air permit and land use approvals were obtained. For example, in periods when construction was stopped, HELCO took steps to ensure contractors were ready to remobilize at a moment's notice. Contractors, consulting engineers, construction managers, and equipment suppliers were kept updated on the latest developments with the permitting. HELCO RT-15E at 4.

Further, HELCO took necessary steps to keep its construction permits and other agency approvals active, such as County building, electrical, and plumbing permits, County water supply commitments, CDUP approvals, the PSD air permit, the State underground injection control permit, the Community noise permit for construction activities, NPDES permits, and the Federal Aviation Administration permit for the exhaust stack. HELCO RT-15E at 4.

In addition, to ensure equipment and material would be ready to install and function properly after installation, HELCO inspected, assessed, and tested equipment and materials during construction down times. Extensive efforts were also made to preserve equipment and material. See HELCO RT-15E at 4.

5. Lack of Viable IPP Alternatives

In Docket No. 7048, the Commission explicitly reviewed the issue of whether IPP proposals were an alternative to CT-4, and found that "HELCO's proposed [CT-4] project is the only viable project with the likelihood of being able to provide critically needed generation in the 1994-1995 time frame." D&O 13050 at 14. The Commission also found that, while permitting problems might delay the CT-4 project, Waimana had not "presented any viable alternatives to CT-4."[19] D&O 13050 at 8; HELCO RT-1 at 26-27.

The Commission also addressed IPP alternatives in the CT-5/ST-7 proceeding and further

[19] Waimana's "interest" in the proceeding stemmed from a partnership (Kawaihae Cogeneration Partners or "KCP") that Waimana formed in the early 1990s with Diamond Energy, to develop a 58 MW fossil-fueled cogeneration power plant on land to be leased by Waimana as a native Hawaiian corporation from DHHL at Kawaihae. Waimana was unsuccessful in negotiating a PPA (for reasons addressed at length in Docket No. 7956, including its extremely high price relative to other options). Waimana's strategy was to oppose HELCO's efforts to develop its own generation (and to enlist and/or finance other opponents), so that HELCO would have no option but to contract with KCP. Ultimately, Waimana's lease at Kawaihae was invalidated as a result of the lack of an Environmental Impact Statement ("EIS"), and Diamond Energy (the partner providing the financing for KCP) discontinued its business in the United States. However, even its own inability to do a project did not prevent it from continuing to oppose and appeal every permit approval obtained by HELCO. HELCO RT-1 at 27.

found that, "[w]hile the need for the next unit is acute, HELCO may not be able to install CT-5 and ST-7 within the time frame it contemplates." At the same time, the Commission noted that the issue of when intervenors Enserch[20] and Waimana/ KCP's "respective facilities can actually be installed is far from settled." D&O 14284 at 12; HELCO RT-1 at 27-28.

With respect to CT-5, the Commission concluded:

> Thus, in this docket, we will continue to leave open the option of HELCO obtaining additional generation through its own facility. We will allow HELCO to continue to pursue construction of its own facility and to commit funds for such purpose, except as reserved in part D below. This authorization is subject to the condition that HELCO, in parallel with its efforts to construct its own facility, negotiate in good faith with Enserch, Waimana/KCP, and any other party that may propose a power purchase contract, to the end that the generating unit that can be most expeditiously put into service at allowable cost, whether constructed by HELCO, Enserch, Waimana/KCP, or any other person, will constitute the next unit to be added to HELCO's system.

D&O 14284 at 12-13; HELCO RT-1 at 28;[21] see also Decision and Order No. 15053 ("D&O 15053"), issued October 4, 1996 in Docket No. 94-0079 at 31; HELCO RT-1 at 31-32; HELCO RT-4A at 27-28.

In response to the Commission's directives and in parallel with its efforts to expeditiously add needed generation at Keahole, HELCO engaged in extensive negotiations for possible PPAs

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[20] Enserch's "interest" in the ST-5/ST-7 Docket arose out of Enserch's role as the developer of a second proposed IPP project. Enserch proposed to install a 60 MW combined cycle facility to be located at the old Haina Mill site. HELCO RT-1 at 28.

[21] The Commission clarified this finding in a subsequent order in which it stated:

> In Docket No. 7623, Decision and Order No. 14284 (September 22, 1995), we held:
>
> The next generating unit to be added to HELCO's system shall be that which can be most expeditiously put into service at allowable cost, whether constructed by HELCO, Waimana/KCP, Enserch, or any other party.
>
> Decision and Order No. 14284 at 17.
>
> By this holding, we did not establish criteria for the selection of the next generating unit. Rather, we simply stated that which is obvious--that is, it is that unit that is most expeditiously put into service at allowable cost that will be the next generating unit added to HELCO's system.

Docket No. 7956, Order No. 16375 (June 9, 1998) at 6.

with KCP and Enserch. HELCO's negotiations with Enserch and Encogen resulted in a PPA which was finalized in June 1997,[22] after Encogen reduced its price to a level at or below avoided costs determined in accordance with: (1) the Commission's rules implementing the PURPA, (2) the Commission's decisions and orders in various IPP proceedings, and (3) a settlement agreement with respect to the remaining avoided cost issues, which was approved by the Commission in August 1997.[23] See HELCO RT-1 at 28-30; HELCO RT-4A at 18-19.

KDC contended that HELCO's efforts to bring CT-4 and CT-5 on line were motivated by an alleged "threat of competition" that KDC claimed "caused the Company to build the Projects as 'cheaply' and as 'fast' as possible . . . ." KDC Position Statement at 1. In effect, KDC claimed that firm capacity proposals from certain IPPs were available to HELCO at the time the Company decided to site new generation at Keahole, and that HELCO deliberately avoided purchasing power from them. See HELCO RT-14A at 14.

These assertions are not supported by any reliable, probative or substantial evidence. HELCO, in parallel with its efforts to construct its own generation, continued to negotiate with IPPs, as contemplated by the Commission in Docket No. 7623.[24] HELCO RT-4A at 25. Moreover, KDC's assertions are contradicted by the Commission's findings in Docket No. 7048 and the evidence presented in the IPP proceedings. The facts demonstrate that:

(1) The Commission explicitly found in Docket No. 7048 that IPP proposals were not a viable alternative to siting CT-4 at Keahole. See D&O 13050 at 8, 14.

(2) There was no showing in Docket No. 7048 and nothing but speculation has been

[22] The PPA was assigned to HEP. HEP's facility commenced commercial operation in two phases in 2000, as was addressed in HELCO's 2000 test year rate case, Docket No. 99-0207. See HELCO RT-1 at 28-29.

[23] HELCO also agreed with the Commission that HELCO should maximize, rather than minimize, its strategies to meet the need for additional capacity on the Big Island. Thus, HELCO determined that it should continue with installation of CT-4 and CT-5 as expeditiously as possible, while entering into a PPA with Encogen. HELCO RT-4A at 18-19.

[24] D&O 14284 at 12-13

offered in this docket to show that any IPP was a viable alternative.

> (3) HELCO did not rely only on adding its own generation to meet its need for new generation. HELCO continued to negotiate with Enserch and KCP, as well as with other IPPs, and ultimately concluded a PPA with Encogen. Encogen only became a viable option from a price standpoint in 1997 – after HELCO's land use entitlement was confirmed by the Third Circuit.

HELCO RT-14A at 14-15.

HELCO reasonably considered other means of meeting the need, including purchasing power from IPPs, and added capacity and energy from IPPs to its system when power was made available or proposed by IPPs on reasonable terms and conditions. HELCO also took extraordinary steps to retain purchased capacity from IPPs when they experienced financial difficulties, including bankruptcy.

a. Waimana/KCP

KCP's proposed facility was never a viable, less contentious, source of power for the Big Island. KCP's pricing proposal was always well above HELCO's avoided cost. In addition, Waimana's land lease at Kawaihae was invalidated as a result of the lack of an EIS, and Diamond Energy (the partner providing the financing for KCP) discontinued its business in the United States.[25] HELCO RT-4A at 15.

b. HCPC

HCPC's short-term Amended PPA was terminated at the end of its five-year contract term. See HELCO RT-4 at 29. As explained by Ms. Giang in HELCO RT-4, it would have been undesirable for HELCO to have kept HCPC on the system and done without CT-5. In summary, having new, fully dispatchable, generation at Keahole is beneficial from a generating and grid

[25] Furthermore, the estimated cost to interconnect a 60 MW dual train combined cycle unit (the type KCP was proposing) at Kawaihae was approximately $20.1 million (1996-$) for the addition of a new line or approximately $16.8 million (1996-$) for a reconductoring option. This is a cost HELCO would not have incurred to add CT-5 to the system. HELCO RT-4 at 33-34.

system reliability standpoint. By contrast, HCPC's facility was subject to substantial constraints with respect to its availability and dispatchability, and was located on the grid where it contributed to transmission system concerns rather than helping to alleviate them. Moreover, the unit (which was installed in the early 1970s) was becoming more prone to forced outages, given the constant cycling of the unit in recent years, and the lower maintenance expenditures in recent years based on the expectation of a 2004 end-of-service date. Its continued operation under the terms of the short-term agreement after the Hawi Renewable Development wind farm was added in 2005 and the Apollo wind farm is repowered in 2007 also would have constrained HELCO's ability to accept as-available renewable energy from these new facilities. HELCO RT-4 at 29-32; HELCO RT-4A at 25.

c. PGV

PGV's project was substantially delayed, which increased the urgency of adding CT-4. (PGV's capacity finally became available on a firm basis at the end of June 1993.) HELCO RT-4A at 5. HELCO acquired an additional 5 MW from PGV in 1996. The Commission approved the purchase of the additional 5 MW in Decision and Order No. 14840, Docket No. 96-0042, dated August 2, 1996. Notwithstanding the purchase of this additional capacity from PGV, there are three primary reasons why it would not have been prudent to purchase an additional large increment of capacity from PGV as a substitute for the capacity from CT-4 and CT-5: (1) Similar to HCPC, PGV is located on the east side of the island and would not help mitigate potential line overloads; (2) Since 2002 PGV has experienced significant difficulties in providing the 30 MW of contracted capacity; and (3) PGV does not provide dispatchable generation, which CT-4 and CT-5 do. PGV must operate at steady output and generally cannot vary its output to follow increasing or decreasing demand on the system. In addition, PGV cannot help offset wind farm power fluctuations and does not help regulate system frequency or voltage, both of which CT-4 and CT-5 do. HELCO RT-4 at 32-33.

d. Steps Taken to Maintain Purchased Power

While waiting for its permits to be finalized, HELCO had to expend substantial efforts to obtain and maintain power deliveries from IPPs with firm PPAs. The Commission was familiar with the delays encountered by PGV in providing firm capacity from Docket Nos. 7048, 7049 and 7623, prior to PGV's commercial in-service date in 1993.[26] The Commission was also familiar with HELCO's efforts to rearrange HCPC's maintenance schedules to maximize available generation, and to modify PPAs to allow continuation of power deliveries from HCPC[27] and Hamakua during the pendency of bankruptcy proceedings, due to filings made by HELCO in Docket Nos. 7093, 7298, 7314, 94-0271, 95-0008, 95-0075 (HCPC), and Docket Nos. 7662, 7732 (Hamakua). The Commission's decision in Docket No. 7623 specifically noted the problems associated with HELCO's power purchases from NUGs, including Hamakua (which went out of business), HCPC and PGV. See D&O 14282 at 8-9. From its informal review of HELCO's generation situation in November 2002 and HELCO's annual Adequacy of Supply letters, the Commission also was kept informed of HEP's unit trips and extended outages after its commencement of commercial service at the end of 2000, and PGV's severe, extended deratings due to well problems since 2002. See HELCO RT-4A at 20-21, 31.

e. HELCO Negotiated in Good Faith with IPPs

KDC suggests that HELCO did not conduct its IPP negotiations in good faith, stating: "If

[26] HELCO added 25 MW of generation from PGV in June 1993, and HELCO was able to conclude a PPA with PGV for an additional 5 MW on February 12, 1996. See Application for Approval of PGV Performance Agreement, filed February 14, 1996 in Docket No. 96-0042. HELCO RT-4A at 31-32.

[27] HELCO was able to preserve HCPC's 18 MW (and increase it to 22 MW), first through 1999 despite its exit from the sugar business, and the announced discontinuation of its power supply activities in connection with its bankruptcy filing in December 1994, and now through 2004. HCPC began supplying an additional 4 MW in May 1995, for a total of 22 MW. To obtain this additional capacity, HELCO agreed to increase payments to HCPC and advanced $2.5 million for capital improvements. HELCO RT-4A at 32.

the Company was unable or unwilling to build a Company-owned facility in a timely manner and at a competitive cost, then the Company should have negotiated with independent power producers in good faith and should have purchased capacity." KDC Position Statement at 1-2.

The Commission has never found that HELCO refused to negotiate in good faith with an IPP, and explicitly rejected KCP's contention to that effect in Docket No. 7956. See Order 14502 at 4. HELCO was unable to conclude a PPA with KCP primarily because its proposed prices were substantially higher than HELCO's long-term avoided costs. HELCO was ultimately able to reach an agreement with Enserch (Encogen) in June 1997 after Enserch reduced its price to a level at or below long-term avoided costs. Enserch reduced its price only after the Commission provided guidance on the avoided cost calculation, and only after HELCO obtained its land use approvals to use its Keahole site. See HELCO RT-4A at 15-16. The Commission also found in Docket No. 7956 "that we are not persuaded that the only obstacle to finalizing a KCP/HELCO contract is HELCO's refusal to sign a PPA." Order No. 14502 at 4. In Order No. 16375, the Commission again rejected KCP's contention that HELCO refused to negotiate in good faith with KCP.[28] See Order No. 16375, issued June 9, 1998, at 4; HELCO RT-4A at 16-17.

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[28] With respect to the general tenor of the negotiations between HELCO and IPPs during the period, some of the negotiations were more contentious than others. The negotiations and proceedings with KCP and Waimana were certainly more contentious than the negotiations and proceedings with Enserch. Initially, KCP claimed that HELCO would not enter into a PPA with any QF because of HELCO's own project at Keahole. For example, in its December 12, 1996 "Motion for Approval of Legally Enforceable Obligation", KCP alleged that "HELCO's proposed solution to the Big Island's generation shortfall . . . concentrates exclusively on favorably resolving the Keahole expansion . . . ." KCP's Memorandum in Support of Motion, filed December 12, 1996 in Docket No. 7956 at 23. However, when it became apparent that HELCO might reach agreement with Encogen, KCP changed its story and alleged that HELCO had "promised the next power plant to EDC" back in 1992. KCP's Memorandum in Support of Motion for Sanctions, filed May 1, 1997 in Docket No. 7956 at 5. KCP even appealed the Commission's ruling that it could not intervene in the Encogen PPA approval proceeding, which appeal was denied by the 1st Circuit Court, and filed a petition with the Federal Energy Regulatory Commission ("FERC") requesting that FERC initiate an enforcement action against the Commission for alleged violations of PURPA. KCP's petition was dismissed by FERC based on HELCO's response. See HELCO RT-4A at 17, 19.

During the period from 1995 to 2000, HELCO negotiated six PPAs. They included: (1) the Amended and Restated PPA with HCPC, dated March 24, 1995 and filed March 31, 1995 in Docket No. 95-0075; (2) the Performance Agreement and Fourth Amendment to the Purchase Power Contract, dated March 24, 1986, as amended with PGV, dated February 12, 1996 and filed February 14, 1996 in Docket No. 96-0042; (3) the PPA with Encogen Hawaii, L.P., dated October 22, 1997 and filed January 16, 1998 in Docket No. 98-0013; (4) a Power Purchase Contract For As-Available Energy with Cyanotech Corporation, dated September 17, 1998 and filed October 23, 1998 in Docket No. 98-0363; (5) the Second Amended and Restated PPA with HCPC, dated October 4, 1999 and filed October 12, 1999 in Docket No. 99-0346; and (6) a Power Purchase Contract For As-Available Energy with Kahua Power Partners, dated August 17, 1999 and filed June 2, 2000 in Docket No. 00-0177. HELCO RT-4A at 20.

HELCO currently relies on IPPs for a substantial portion of its capacity (HEP, PGV) and energy (HEP, PGV, HRD, Apollo, etc). As stated in HELCO T-5, in the 2006 test year, HELCO estimated that it would purchase approximately 710.1 GWh in energy, which represents approximately 57% of the total net energy produced of 1,251.2 GWh required in the test year 2006.[29] HELCO T-5 at 85. HELCO purchases power from IPPs under PPAs negotiated with each IPP, and which have been approved by the Commission. See HELCO RT-4A at 16, 19-20.

6. Proceeding in Parallel

HELCO provided the Commission and the Consumer Advocate with the reasons for proceeding in parallel with the installations of CT-4, CT-5 and the Encogen facility in a number of dockets. In short, the parallel plan allowed HELCO to: (1) increase its opportunity to install generation as soon as possible; (2) address the possibility that the Encogen facility or HELCO's

[29] The percentage is expected to be higher in 2007, since the repowered Apollo Energy Corporation wind farm has commenced operations under the Amended and Restated Contract approved by the Commission in Docket No. 04-0436.

Keahole additions might be further delayed; (3) meet the continuing need for generation after the "next" increment of generation was added to HELCO's system; (4) add generation in West Hawaii (and, ultimately, to complete an efficient DTCC unit at Keahole), given the imbalance between the amount of HELCO's system load in West Hawaii and the small amount of generating capacity that HELCO had in the region; and (5) obtain the benefits from HELCO's planned unit additions at Keahole for which most of the expenditures already had been incurred. See HELCO RT-1 at 29-30.

HELCO determined in early 1997 that it would be prudent to proceed with the installation of generation at Keahole (i.e., to complete the installation of CT-4 and CT-5), while at the same time entering into a PPA with Encogen.[30] At the same time, in order to reduce the rate impact to the customers, HELCO deferred the planned installation of ST-7, and planned to put some of its own capacity (at that time, its Puna steam unit) on cold standby reserve status until additional generation was needed. (HELCO also stopped accruing AFUDC on CT-4 and CT-5 in December 1998.) See HELCO RT-1 at 23, 29; HELCO RT-4A at 26.

HELCO's generation resource plan provided the basis for the continuing need for

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[30] On July 31, 1995, the Commission issued D&O 14030 in the KCP proceeding, which provided guidance on the calculation of avoided costs and other issues that HELCO and KCP could not agree on during earlier negotiations. In response, HELCO recalculated avoided costs for both KCP and Enserch, and provided both IPPs with a proposed PPA. After the issuance of Order No. 14502, issued January 26, 1996 in the KCP proceeding providing further guidance, HELCO revised its avoided cost calculation for KCP and Enserch accordingly. KCP wanted HELCO to ignore Enserch, and only negotiate with KCP. HELCO's decision to provide the same kind of information to Enserch absent a decision and order in Docket No. 94-0079 was affirmed in D&O No. 14284 in Docket No. 7623 (regarding commitment of funds for the purchase and installation of CT-5 and ST 7). In order to facilitate the negotiations, Docket No. 94-0079 was also reopened by stipulation at HELCO's suggestion. PPA negotiations occurred between September 1995 and June 1997. HELCO RT-4A at 17-18.

The Encogen facility at Hamakua did not become a viable option from a price standpoint until 1997 – after HELCO obtained its Keahole land use authorizations. HELCO and Encogen finalized the price, terms and conditions of their PPA in 1997. Encogen waived its financing "out" in January 1999, and its final air permit was received in April 1999. The PPA (as amended to extend the time for approval after the Consumer Advocate initially opposed approval of the PPA) was approved in July 1999, and the PPA became effective after the period for appeal expired as of August 23, 2000. See HELCO RT-1 at 29; HELCO RT-4A at 25-26.

generation after the "next" increment of generation was added to HELCO's system . Since the early 1990's HELCO's plan included: (1) the phased installation of a DTCC unit at HELCO's existing Keahole power plant, with the first two phases consisting of CTs (CT-4 and CT-5), and the last phase consisting of a STG (ST-7) and related facilities; (2) followed by the phased installation of generic DTCC units at a new West Hawaii site;[31] and (3) the retirements of existing older, smaller units as new generation is installed. See D&O 13050; D&O 14284; Decision and Order No. 14708, Docket No. 7259, filed May 29, 1996 ("D&O 14708"); HELCO RT-4A at 28-29.

The need for additional generation was addressed in Integrated Resource Planning ("IRP"). For example, HELCO's 1993 IRP Plan approved in Docket No. 7259 (which was developed prior to PPA amendments moving up the termination date for the HCPC PPA to December 31, 1999) included 56 MW (net) of generating capacity to be added by the end of 1997, with additional generation to be added in subsequent years. See D&O 14708; HELCO RT-1 at 25; HELCO RT-4A at 4. The 1996 generation resource plan used in the calculation of avoided costs for the Encogen (now HEP) facility included the phased installation of the second DTCC unit beginning in 1999 (to reflect the change in HCPC's termination date, and the addition of 5 MW from PGV). See HELCO RT-4A at 29.

The urgency with respect to Keahole generation did not end when HELCO reached

[31] HELCO's generation expansion plans also included the need for subsequent increments of generation (of 20 MW or more), generally in the 1999 and 2001 timeframes. For example, HELCO's biennial Electric Utility System Cost Data filing (July 1, 1996) showed the addition of CTs in 1999 and 2001 after the completion of a DTCC facility. In addition, HELCO's need for additional generation in the 1999 timeframe, even if a dual train combined cycle unit was completed at either Keahole or at Hamakua, was shown in the generation expansion plans filed by HELCO (1) in the dockets arising out of its request for approval to commit funds for the Keahole generation additions, (2) the dockets commenced at the request of qualifying facilities seeking to enter into power purchase agreements with HELCO, (3) HELCO's Integrated Resource Planning proceeding, and (4) the contingency planning docket, Docket No. 94-0140. See HELCO RT-1 at 30; HELCO RT-4A at 3.

agreement on a PPA with Encogen in 1997. The Keahole additions were much further along and were expected to be in service sooner than the Encogen facility, and there was still substantial uncertainty as to the timing of the Encogen facility,[32] as was explained at the time agreement was reached with Encogen and when approval of the Encogen PPA was requested. As HELCO indicated in numerous filings with the Commission, the in-service dates for the two phases of the Encogen facility were uncertain, even after HELCO signed its PPA with Encogen. At the time that HELCO and Encogen finalized the price, terms and conditions of their PPA in 1997, there were three principal factors that could delay Encogen's in-service date: (1) receipt of its financing commitment; (2) receipt of its final air permit; and (3) receipt of a final, non-appealable Commission approval of the PPA. For this and other reasons, HELCO continued to proceed in parallel with the Encogen PPA and the additions of CT-4 and CT-5. See HELCO RT-1 at 31; HELCO RT-4A at 5-6.

HELCO had successfully pursued the strategy of expediting the installation of its own generation, while planning in parallel for the addition of purchased power, on a prior occasion. For example, HELCO filed its application for the commitment of funds for CT-3 on February 16, 1990, and HELCO subsequently committed to the purchase of the CT in order to meet a schedule for the installation of the unit in 1992 if the provision of power by PGV continued to be delayed. HELCO was able to install the unit and have it operational in July 1992, as a result of which it averted the need for further rolling blackouts on HELCO's system despite the continued absence of PGV for another year. The Commission's decision and order in Docket No. 6643 was issued on March 23, 1992. Had HELCO waited until the decision and order was issued to commit to

[32] Given the status at the time of the necessary permits and approvals, it appeared that CT-4 and CT-5 could be installed in 1998. However, as HELCO also stated at the time, it was possible that either CT-4/CT-5 would end up being installed first, or that Encogen's Phase 1 and/or Phase 2 would end up being installed first. HELCO RT-4A at 26.

the purchase of the CT, HELCO would not have been able to complete installation of the unit until approximately 1994. The impact on HELCO's system reliability and on its customers would have been severe, particularly in the period preceding the availability of power from PGV beginning in June 1993. HELCO RT-1 at 32.

The importance of parallel planning and parallel plans has been recognized in other Commission proceedings. In the recent Competitive Bidding docket, the Consumer Advocate asked the Commission to explicitly recognize a utility's obligation to do parallel planning pursuant to its obligation to serve. In Decision and Order No. 23121 ("D&O 23121"), issued December 8, 2006 in Docket No. 03-0372, the Commission found that its Competitive Bidding Framework "does not relieve the electric utility from its obligation to provide safe and reliable electric service to its customers, including the obligation to resolve reliability problems, both short- and long-term, and that the Framework's provisions do not implicitly relieve the utility from this basic, underlying obligation to serve." D&O 23121 at 13; HELCO RT-1 at 33.

The Competitive Bidding Framework attached to D&O 23121 explicitly recognizes the importance of parallel planning. For example, Section II.D.2 states that:

> In consideration of the isolated nature of the island utility systems, the utility may use a Parallel Plan option to mitigate the risk that an IPP's option may fail. Under this Parallel Plan option, the utility may continue to proceed with its Parallel Plan until it is reasonably certain that the awarded IPP project will reach commercial operation, or until such action can no longer be justified to be reasonable.

As a result, Section VII.B provides that: "The costs that an electric utility incurs in taking reasonable and prudent steps to implement Parallel Plans and Contingency Plans are recoverable through the utility's rates, to the extent reasonable and prudent, as part of the cost of providing reliable service to customers."[33] HELCO RT-1 at 33.

[33] The Commission has recognized that utilities must be assured a fair opportunity to earn a reasonable

7. **Need for CT-5**

The additional capacity provided by CT-5 was and is needed to maintain an adequate generation reserve margin for the HELCO system. Moreover, the availability of CT-5 provides additional benefits that are and will need to be utilized by HELCO because of its location at Keahole including: (1) helping to mitigate potential transmission line overloads in the event of outages of certain transmission lines; (2) helping to reduce the need to install an additional cross-island transmission line to carry power from East Hawaii, where most of the generating resources are located, to West Hawaii, where about one-half of the electrical power on the island is consumed; (3) reducing fuel costs by reducing the amount of transmission system losses and by providing more efficient generation at Keahole that is used to mitigate potential transmission line overloads; (4) facilitating the reconductoring of certain transmission lines; and (5) helping to accommodate renewable energy on the system. See HELCO RT-4 at 17; HELCO RT-4 at 34; HELCO RT-1 at 10.

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return on the capital prudently committed to the business. In addition to the language in the general public utilities law (HRS § 269-16(b)(3)), the recovery of costs prudently incurred by a utility in meeting its obligation to service is based in large part on the "long-standing regulatory compact", which the Commission has described as follows:

> The regulatory compact has two aspects: (1) in return for a monopoly franchise, utilities accept the obligation to serve all comers; and (2) in return for agreeing to commit capital necessary to allow the utilities to meet the obligation, utilities are assured a fair opportunity to earn a reasonable return on the capital prudently committed to the business. In Wash. Util. And Trans. Comm'n v. Puget Sound Power & Light Co., 62 P.U.R.45th 557, 581 (1984), the Washington Commission explained the regulatory compact in this fashion:
>
> > "The social and economic compact of utility regulation begins with the premise that a regulated utility has an obligation to serve the public. [A] utility possesses an unending obligation to provide service to anyone within the service territory of that utility who demands service in accordance with approved tariffs.
> >
> > However, in order for the social duty to serve to be viable, the compact must also provide for a utility to recover expenses it prudently undertakes to meet the obligation."

See Re Citizens Utilities Company, Kauai Electric Division, Docket Nos. 94-0097 & 94-0308, Decision and Order No. 14859, filed August 7, 1996 at 13; HELCO RT-1 at 34.

Ms. Giang in HELCO RT-4, and Mr. Dizon[34] in HELCO RT-4A, discussed the general benefits of siting generation in West Hawaii, and the specific benefits of having CT-4 and CT-5 at Keahole. The benefits of having CT-4 and CT-5 at Keahole are discussed from the perspective of HELCO's Production Manager in HELCO T-5 at 28-32.

a. CT-5 Benefits

The presence of CT-5 on the system helps maintain a sufficient amount of reserve margin to be able to serve the expected peak demand even with a unit unavailable due to planned maintenance and with the largest available unit forced out of service due to an unexpected problem.[35] CT-5 also helps maintain generating system reliability in the event small to large increments of generating capacity are lost from service for extended periods of time, as has happened with the PGV 30 MW geothermal unit and the HEP 60 MW combined cycle unit. See HELCO RT-4 at 21.[36]

For example, in April 2002, the output of the PGV plant was derated to an average of 5.6 MW for at least 8 months due a problem with one of their supply wells. This was a significant loss of 24.4 MW of generation for an extended period of time. (This is greater than the rating of

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[34] Jose Dizon has joined HELCO as the Manager of its Engineering Department, and was the Director of Generation Planning for HECO from 1995 to 2000.

[35] HELCO RT-4 at 17-18; see HELCO RT-4 at 18 and HELCO-R-410 (HELCO's capacity planning criteria); see also HELCO's 2007 Adequacy of Supply report, filed January 30, 2007 ("HELCO 2007 AOS Report") at 2 n.3; HELCO RT-4 at 18-19 (HELCO's planning criteria include a consideration of maintaining a minimum reserve margin of approximately 20%, which may be higher depending on system conditions).

[36] Capacity may be added to the system for reasons other than to meet the capacity planning criteria. HELCO's capacity planning criteria document further states: "The actual commercial operation date for the next unit to be added shall be determined . . . with due consideration given to short-term operating conditions, equipment procurement, construction, regulatory approvals, financial and other constraints, etc." HELCO-R-410 at 2; HELCO RT-4 at 19. As stated earlier, the Commission has recognized that the timing of generation additions cannot be determined solely through application of the generation planning criteria, because the criteria do not consider a number of factors (i.e., power purchase uncertainties and the application of generation capacity expansion criteria). HELCO has incorporated these considerations into its IRP Planning. HELCO's IRP-2 report, filed with the Commission on September 1, 1998, in Docket No. 97-0349, at 5-1; see HELCO RT-4 at 20.

CT-4 or CT-5, which have a normal top load rating of 22 MW-net.) HELCO RT-4 at 22. HELCO also has experienced the loss of small to large increments of generating capacity from the HEP 60 MW combined cycle unit. For example, in the period from January 9, 2006 to January 17, 2006, HEP experienced an unexpected outage of its steam unit. The steam unit was scheduled for an outage of five days from January 9, but it experienced a forced outage and was not returned until January 18. HEP was able to produce only approximately 40 MW of its 60 MW output with two combustion turbines operating in simple cycle mode. However, the cost of operating HEP in simple cycle CT mode is higher than operating CT-4, CT-5, and most of HELCO's existing units. Therefore, although HEP was available to produce 40 MW, due to economic dispatch HEP was operated at approximately 20 MW with one combustion turbine in simple cycle operation. Both Keahole CT-4 and CT-5 were operating to serve the system load economically. HELCO RT-4 at 22-23. Significant deratings of PGV and HEP are not uncommon. Having CT-5 on the system provides a "cushion" of reserve margin to maintain generating system reliability during events like these. See HELCO RT-4 at 22-23.

CT-5 also helps mitigate potential transmission line overloads. As explained by Ms. Giang, CT-4 and/or CT-5 are operated for more hours, at higher output levels, and generate more energy than they otherwise would under economic dispatch in order to mitigate the potential for line overloads of certain transmission lines under contingency situations where certain other transmission lines are unexpectedly lost from service. CT-4 alone cannot serve this function as it must sometimes be taken out of service for routine maintenance, or at times, the unit may be forced out of service due to an unexpected problem. CT-4 and CT-5 share this duty to mitigate potential transmission line overloads. See HELCO T-4 at 23-25; HELCO response to CA-SIR-3; HELCO RT-4 at 23.

Another benefit of CT-5 is that it helps to reduce the need to install additional cross-island transmission lines. Currently, there are four cross-island transmission lines carrying power from the east side of the island, where most of the generation is situated, to the west side, where about one-half of the island's demand is. As the imbalance between demand and generation on the west side increases, these cross-island transmission lines may reach the limit that they can safely and reliably carry power. Once they reach their limit, additional east-to-west (i.e., cross-island) transmission capacity would need to be installed. Locating generating capacity in the west side of the island (i.e., at Keahole), reduces the imbalance between demand and generation which reduces the need to export power from east to west and therefore helps to reduce the need to install additional cross-island transmission capacity. HELCO RT-4 at 24 (citing Docket No. 99-0207); HELCO RT-4A at 16.

In addition, CT-5 helps reduce fuel costs in two ways. First, by providing generation on the west side of the island since 2004, it is estimated that system transmission losses have been reduced by 0.5%, saving about $1.0 million per year. HELCO RT-4 at 24. Second, had CT-5 (and CT-4) been located on the east side of the island, less efficient existing generation at Keahole (i.e., Keahole CT-2) would need to be run for more hours and generate more energy than it otherwise would under economic dispatch in order to mitigate the potential for overloading certain transmission lines under contingency situations where certain other transmission lines are unexpectedly lost from service.[37] It is estimated that running CT-5 (or CT-4) instead of CT-2 saves about $1.9 million per year. These cost savings will increase when CT-4 and CT-5 are converted to a DTCC unit with the addition of ST-7 in 2009 because the units will be in baseload operation and further reduce transmission losses and heat rate. See HELCO

[37] For example, the heat rate of Keahole CT-2 is about 14,700 Btu/kWh-net at full load. By comparison, the heat rate of CT-5 (or CT-4) is about 12,200 Btu/kWh-net at full load.

RT-4 at 25.

Moveover, the presence of CT-5 will facilitate the sequential reconductoring of the 69 kilovolt ("kV") transmission lines that run from Keamuku to Keahole (the "6800 line"), from Waimea to Keamuku (the "7200 line"), and from Waimea to Ouli (the "7300 line"). These lines are located in the northwestern part of the island and, as explained in HELCO T-4 at 24 and in HELCO's response to CA-SIR-3, may become overloaded under certain situations. Therefore, HELCO plans to "reconductor" these lines (i.e., replace the existing conductors with new conductors with higher power carrying capacity) in the coming years. See HELCO RT-4 at 25-26. While the reconductoring work is in progress, Keahole CT-5, along with Keahole Units CT-2, CT-4 and diesel units D21 to 23, may be called upon to aide in minimizing the line loadings such that the remaining in-service transmission lines are within their continuous rating depending on the system load. HELCO RT-4 at 26.

Further, CT-5 helps to accommodate renewable energy by providing voltage regulation and load following capability, which as-available renewable generating resources (and sometimes even firm renewable resources) are unable to provide. In addition, because CT-5 can be turned off during the off-peak periods, more renewable energy, either as-available or firm, can be accepted by the system during this period. HELCO RT-4 at 26-27.

CT-4 and CT-5 are combustion turbines that have fast-start capability. They can start-up in minutes and once on-line they can add or reduce power output quickly. This allows them to balance generation and load during post-contingency situations such as a generating unit trip or a transmission line outage. In addition, this balancing capability makes possible the addition to the grid of more as-available renewable energy sources, such as wind power, which by their nature have large variations of energy output over time. The CTs have the flexibility to adjust the amount of firm capacity and regulating capacity HELCO has to have online to match system load, which can fluctuate from hour-to-hour depending on the amount (and intermittent nature of) the as-available energy being provided to the system. The ability to smooth out energy output enables the grid to incorporate renewable as-available energy sources and provide sufficient and uninterrupted power to consumers. HELCO RT-1 at 11-12.

CT-4 and CT-5 also will make it possible to complete a DTCC plant at Keahole, with the planned addition of a STG (ST-7), which will run on waste heat from the CT-4 and CT-5 units, but without the need of additional fuel oil. HELCO RT-1 at 12; HELCO T-4 at 16.

b. CT-5 is Used and Useful for Utility Purposes

There is no question but that CT-5 is both actually used[38] and useful, and is critical to providing reliable service to customers on the Big Island. Moreover, there would be no basis for a finding that any of HELCO's less used generation is somehow "excessive" now that CT-5 (and CT-4) are available and HELCO's reserve margin has been restored to an acceptable level. It is not feasible for a utility to exactly time the addition of new generation with load growth, since plans for new generation must be based on forecasts and take into account uncertainties, and implementation must be commenced years in advance of the forecast need. HELCO is not aware of any instance in which the Commission has denied the inclusion in rate base of new or existing generating units where (1) the utility had taken prudent steps to meet the future needs of its customers in adding new generation, and (2) the generation challenged as being excess was actually being used. A proposal to exclude the cost of such generation would ignore not only the public service obligation of utilities, but also the realities of resource planning and the adverse financial consequences that would inevitably ensue for the utility and its ratepayers. See

[38] In 2006, CT-5 ran for 4,052 hours and produced 57,700,090 kWh.

HELCO RT-4 at 35-36.

C. SITING AND PERMITTING

1. Introduction

The Keahole Project background and permitting history are summarized in Appendix C to the Keahole Cost Report, and details of the related administrative agency and court proceedings were included in the Monthly Status Reports. Additional discussion was included in the rebuttal testimonies of (1) Warren Lee, HELCO RT-1 and R. Ben Tsukazaki, HELCO RT-15F (land use permitting); (2) Scott Seu, HELCO RT-15A and James Clary, HELCO RT-15B (air permitting); and (3) Barry Nakamoto, HELCO RT-15C (ground water usage).

The siting of CT-4 and CT-5 at Keahole should not be an issue in this docket. The Commission, in its 1994 decision approving the commitment of expenditures for CT-4: (1) found that HELCO had an urgent need for generation in the 1994-1995 time frame; (2) concluded that the Keahole site is large enough to encompass not just CT-4 but also CT-5, if HELCO decided to pursue that option; (3) recognized that permitting problems might delay CT-4; and (4) ruled that, "In light of present and foreseeable circumstances, we conclude that the location of CT 4 at Keahole is reasonable." See D&O 13050 at 12.

Documents indicating that installing new generation at Keahole would encounter opposition do not show (just as there was no showing in Docket No. 7048, where the issue was litigated) that the decision to site new generation at Keahole was imprudent, or that another option would have been preferable. The mere fact that there may have been alternative options that could have been pursued does not make or show that the selected option was imprudent. Similarly, the fact that the selected option may have been "contentious" does not render selection of the option imprudent. HELCO RT-1 at 41-42.

HELCO was aware that there would be opposition to siting additional generation, and to siting such generation at Keahole. The fact that there was opposition was discussed at length in Docket No. 7048. As a result of the expected opposition, HELCO did not undertake the task of obtaining the necessary approvals and permits lightly, or without obtaining expert assistance.

HELCO's efforts to obtain an Amendment to its existing CDUP resulted in a "default entitlement", which was confirmed by the Third Circuit in February 1998, and was affirmed by the Hawaii Supreme Court on appeal in July 2003.

HELCO has addressed issues raised by KDC with respect to the construction period applicable under HELCO's default entitlement, and HELCO's efforts to extend the period after the Third Circuit ruled in September 2000 that a three-year construction deadline applied from April 1996.[39] See HELCO RT-1 at 46-56; HELCO RT-15F at 15-17. Further information in the form of documents and pleadings is available in the Monthly Status Reports.[40]

With respect to whether HELCO should have pursued reclassification and rezoning of the Keahole site, rather than the CDUA, HELCO had a valid basis for requesting a CDUA.[41] The facts in the record cannot support a finding that the decision to request a CDUA was unreasonable or imprudent or resulted in foreseeable delay, and such a finding cannot be based on conjecture or "what if" speculation.

HELCO was not imprudent in expecting that it would obtain the permits necessary to install additional generation at Keahole. Rather, HELCO's judgment that the necessary permits and approvals would be obtained despite the opposition was ultimately borne out. HELCO obtained the land use authorization it needed to install new generation in 1996, although it was

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[39] KDC's Responsive Statement at 3, 18.
[40] See, e.g., BLNR's Findings of Fact and Conclusions of Law, Decision and Order in DLNR File No. 01-03-HA dated March 23, 2002, which was included as Attachment 2 to the April 4, 2002 Status Report.
[41] HELCO RT-15F at 1-13.

not judicially confirmed until 1997. After that, the only remaining permit needed for the installation of generation at Keahole was the air permit. The delays encountered in obtaining the final air permit were extraordinary, and were well beyond HELCO's reasonable control. HELCO took diligent and prudent steps to obtain the PSD air permit, and HELCO could not have reasonably anticipated the substantial delays in the PSD air permit process. HELCO RT-1 at 39.

The delays experienced in obtaining the necessary permits and approvals were extraordinary in that they were unprecedented in Hawaii for a generation project. Part of the reason for that was the unprecedented efforts of an IPP to oppose HELCO's efforts, in an attempt to leave HELCO with no option but to accept its proposal. Waimana/KCP sponsored testimony at one of HELCO's air permit hearings, appealed the air permit to the EAB, and directly opposed the Keahole CDUA in numerous administrative proceedings and litigations. HELCO RT-1 at 39.

As indicated above, HELCO anticipated community opposition, and took steps to address the anticipated concerns. However, the degree of opposition experienced by HELCO in the 1993-1994 timeframe (and continuing until a settlement was reached in 2003) with respect to CT-4 and CT-5 was unexpected, as the community reaction to CT-4 and CT-5 was significantly greater than HELCO experienced with CT-3, and the prior experience of other utilities installing generation in the islands. HELCO RT-1 at 40-41.

2. Siting at Keahole

a. The Commission's Determination that HELCO's Siting Decision was Reasonable

HELCO's decision to site CT-4 at Keahole was an explicitly stated issue in Docket No. 7048. Specifically, the third issue in Stipulated Prehearing Order No. 11903, filed on October 7, 1992, was "[w]hether the location of HELCO's CT-4 is reasonable in light of present and foreseeable circumstances." See D&O 13050 at 2; HELCO RT-1 at 40.

Subsequently, the Commission, in its 1994 decision approving the commitment of expenditures for CT-4: (1) found that HELCO had an urgent need for generation in the 1994-1995 time frame; (2) concluded that the Keahole site is large enough to encompass not just CT-4 but also CT-5, if HELCO decides to pursue that option; (3) recognized that permitting problems might delay CT-4; and (4) ruled that, "In light of present and foreseeable circumstances, we conclude that the location of CT 4 at Keahole is reasonable." See D&O 13050 at 12; HELCO RT-1 at 40, 56-57.

Consistent with the Commission's explicit finding in 1994 that it was reasonable to site CT-4 at Keahole, the Consumer Advocate stated in this docket that it was not contesting HELCO's decision to add generation in West Hawaii. See Response to HELCO/CA-IR-318. In response to the direct question of whether the Consumer Advocate took the position that HELCO should have pursued a different generation option at an alternate site, instead of locating CT-4 and/or CT-5 at Keahole, the response was that: "It is not the Consumer Advocate's position that HELCO should not have located CT-4 and CT-5 at Keahole." See HELCO RT-1 at 37-38.

b. The 1988 West Hawaii Site Study

HELCO's decision to site new generation in West Hawaii, HELCO's extensive efforts to obtain a new generating station site for up to 200 MW of generation in West Hawaii, and the suitability of the Keahole Power Plant site for the addition of the combined cycle facility, were addressed at length in Docket No. 7048. See D&O 13050 at 10-12. In brief, the power plant was a permitted use at the Keahole site, and a generating plant already existed at Keahole. In addition, there was adequate undeveloped area at the Keahole Power Plant site to site the full combined cycle facility. HELCO RT-1 at 38.

CH2M Hill's August 1988, West Hawaii Site Study (to which KDC refers at page 18 of its Position Statement), was provided and discussed in the proceedings reviewing the commitments of expenditures for CT-4 and CT-5/ST-7. It documents HELCO's efforts to obtain another site in West Hawaii for a new generating station (to locate up to 200 MW of generation). As a result of the study, HELCO undertook extensive efforts to obtain another site, as documented in those proceedings. The study does not indicate that efforts to site a 56 MW generating unit at the existing Keahole generating station would incur the extended land use and air permitting delays that ensued. Nor does it indicate that other sites would not be subject to permitting challenges and opposition, as was the case at Kawaihae. HELCO RT-1 at 42.

Concerns expressed in the 1988 West Hawaii Site Study regarding siting a 200 MW West Hawaii generating facility at Keahole (to which the Consumer Advocate and KDC refer), generally were not applicable to the proposed siting of a 58 MW (gross) unit, and HELCO addressed those concerns that might be applicable to the combined cycle unit. HELCO's testimony in Docket No. 7048 also summarized the efforts undertaken by HELCO to address concerns at Keahole such as visual impact and noise. HELCO RT-1 at 38-39, 42.

c. Opposition to the Keahole Site

The Consumer Advocate and KDC pointed to various statements in documents indicating that there would be opposition to siting additional generation at Keahole. See, e.g., CA-T-3 at 88-92. However, the matters referred to generally occurred prior to the Commission's finding in D&O 13050. See HELCO RT-4A at 41.

It is always possible to speculate after-the-fact as to what could have been done differently. However, the question of what should have been done must be addressed based on the facts and circumstances as they existed at the time decisions were made. The best way to decide whether a decision is prudent without relying on 20-20 hindsight is to evaluate the decision at the time it is made. That is exactly what the Commission did in Docket No. 7048. HELCO RT-1 at 44. The Commission was aware that there would be opposition. Nonetheless, its finding was based on all of the evidence before it, and not just the few matters cited taken in isolation. See HELCO RT-1 at 41. HELCO's efforts to obtain another site, and HELCO's reasons for returning to the Keahole site are discussed below.[42]

HELCO was aware that there would be opposition to siting additional generation, and to siting such generation at Keahole. The fact that there was opposition was discussed at length in Docket No. 7048. As a result of the expected opposition, HELCO did not undertake the task of obtaining the necessary approvals and permits lightly, or without obtaining expert assistance. For example, as discussed above, HELCO retained CH2M Hill, which provided extensive testimony in Docket No. 7048, to handle the land use permitting. See HELCO RT-1 at 40.

d. DLNR Did Not Require an Alternate Site

KDC states that "[w]hen the Company installed CT-2 at the Station in 1988, it informed the State Board of Land and Natural Resources (the 'Board' or 'BLNR'), which regulated the Conservation district in which the Station was located, that it would not expand the Station further."[43] In 1988, HELCO did not intend to install further generation at Keahole. The long term plan in the time frame in which HELCO obtained the CDUA for CT-2 was to rely on geothermal power. However, as HELCO established in the CT-5 docket, the DLNR did not impose any conditions on HELCO that prohibited the Company from applying for further

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[42] Jose Dizon, who joined HELCO as the Manager of its Engineering Department, and who was the Director of Generation Planning for HECO from 1995 to 2000, in HELCO RT-4A, and Lisa Giang, in HELCO RT-4, addressed the benefits of siting the new generation at Keahole. HELCO RT-1 at 17.

[43] KDC Position Statement at 5 (citing DLNR Staff Report, dated September 23, 1988, at 6; June 1988 CDUP application at 17-18; and DLNR Staff Report, dated January 21, 1993 at 2, 3-4).

expansion at Keahole.[44] In addition, HELCO took extensive steps to obtain another site in West Hawaii, before determining that additional generation should be added at Keahole due to the exigent circumstances. HELCO RT-1 at 43.

e. Alternate sites

Although the Consumer Advocate did not directly contest the decision to site generation at Keahole, the Consumer Advocate proposed in its direct testimonies that the Commission disallow certain CT-4 and CT-5 costs, based on the claim that certain costs (i.e., noise abatement and landscaping costs) might have been avoidable if CT-4 (and CT-5) had been located at another site, or if HELCO had selected another, unspecified option. See CA-T-3 at 95-96. The Consumer Advocate's witness, Mr. Carver, also posed the following questions in his Direct Testimony: "Had HELCO chosen an alternate site for CT-4 (and CT-5), could the units have been completed and brought on-line sooner even though HELCO did not own property at the time?" CA-T-3 at 95.

i. Kawaihae and Puu Anahulu

There was a suggestion that Kawaihae would have been a better site for CT-4 and CT-5. However, a Kawaihae site was not available to HELCO.

The intention was to have CT-4 be the first generating unit at HELCO's proposed new 200 MW West Hawaii generating facility. See HELCO RT-1 at 44-45; HELCO RT-4A at 10. A site at Kawaihae initially was selected based on a site selection study commissioned by HELCO in the late 1980s. This 1988 West Hawaii Site Study prepared by consultant CH2M Hill had identified a Kawaihae site located about a mile north of the Harbor area as a preferred site based on a variety of evaluation factors and input from a broad cross-section of community advisors. However, HELCO's efforts to acquire a site at Kawaihae from DHHL were unsuccessful. See

[44] See Transcript of Proceedings held July 18, 1994 at 590 (Lyman), Docket No. 7623.

HELCO RT-1 at 45; HELCO RT-4A at 10.

HELCO's efforts to obtain a Kawaihae site for CT-4 were detailed in Docket No. 7049, in which the Commission found that siting CT-4 at Keahole was reasonable. HELCO discussed with DHHL how it could qualify as a lessee or sublessee for the Kawaihae Site. However, DHHL adopted a preference to award the lease to a native Hawaiian corporation. If no native Hawaiian corporation was selected, then HELCO and other non-native Hawaiian bidders might have had an opportunity to be considered. See response to CA-IR-500(c); HELCO RT-1 at 45-46.

HELCO then attempted to procure a site at Puu Anahulu, owned by the State of Hawaii. This area was also on the list of preferred sites identified in the 1988 West Hawaii Site Study. Efforts to acquire this site from the State of Hawaii were also unsuccessful. See HELCO RT-1 at 45; HELCO RT-4A at 10.

In late 1992, with the need date for additional generating capacity approaching, HELCO evaluated its options and determined that installing CT-4 at its existing Keahole Power Plant and separating the next generation addition from the longer-term efforts to acquire a new West Hawaii site was prudent. Accordingly, in August 1992 HELCO applied for an amendment to its existing CDUP at Keahole and in September 1992, HELCO filed an amendment to its Commission application identifying the Keahole site as the location for the CT-4 unit. HELCO RT-1 at 45; HELCO RT-4A at 10-11.

ii. KCP's Kawaihae Site

A question also was raised as to whether HELCO could have subleased a Kawaihae site from Waimana. HELCO did have discussions with Waimana regarding the alternate Kawaihae site leased to Waimana, but Waimana did not make an "offer" to sublease.[45] Waimana generally conditioned any sublease on a PPA between KCP and HELCO, after which it would then discuss site subleasing arrangements.

In written testimony submitted on December 18, 1992 in the CT-4 docket, Waimana suggested that, instead of proceeding with CT-4 at Kawaihae, HELCO should contract with KCP to purchase power from the 58 MW combined cycle facility KCP proposed to build at Kawaihae, if Waimana obtained a lease from DHHL, or that CT-4 be sited at Kawaihae on the site Waimana hoped to lease from DHHL in conjunction with such a PPA. In IR responses and at the hearing in February 1993, Waimana agreed that there were numerous contingencies that would have to be resolved to permit CT-4 to be installed at Kawaihae. First, HELCO would have to enter into a PPA with KCP for a 58 MW combined cycle unit as a condition to the sublease. In addition, since the unit would be installed at Kawaihae in conjunction with a KCP generation facility, Waimana would have to be awarded the rights by DHHL to negotiate a lease, and would have to complete the negotiations. If a portion of the property were subleased to HELCO, DHHL would have to approve the sublease, which could result in renegotiation of the lease rent.

After Waimana was awarded a lease of the Kawaihae harbor site, there were further discussions, and a meeting in February 1994, regarding the possibility of a sublease not conditioned on a KCP PPA. Waimana took the position that the sublease "rent" would have to cover its DHHL rent plus its development costs and lost profit from not doing a PPA on its terms, and concluded that that would not be a viable option for HELCO to pursue.

It should also be noted that there was considerable opposition to locating a power generating facility at this alternate Kawaihae site from certain DHHL homestead residents, as

[45] See response to CA-IR-500(a).

well as some of the homeowners in the adjacent Mauna Kea resort community. After litigation, the lease was declared void in October 1999, based on a ruling that completion and finalization of an EIS was a condition precedent to DHHL's authority to enter into the lease.

iii. HELCO's Contingency Plan

HELCO considered repowering of existing generation at its Puna or Hill Power Plants as part of its contingency planning to address delays in adding new generation. HELCO analyzed these repowering options in the March 1996 HELCO Contingency Plan Update. See HELCO RT-4A at 12.

Of the five repowering options analyzed, Puna repowering option 4 was the preferred contingency option. HELCO did not intend to proceed with Puna repowering option 4 instead of Keahole CT-4 and CT-5. The repowering option was intended to be a contingency option and was not intended to replace the Keahole DTCC project:

> (1) One of HELCO's strategies has been to maximize its generation options by accelerating new additions. HELCO's contingency plan would have been to proceed in parallel with the Keahole DTCC and the Puna repowering project, if a firm PPA for a large increment of new capacity could not be negotiated. HELCO RT-4A at 13.
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> (2) A primary objective of HELCO's was to install new generation on the west side of the Big Island, closer to load growth, not on the east side where Puna and Hill are located. If HELCO had gone back to Puna, even more generation would have been sited on the east side of the Big Island, which would impact long-term transmission capital costs and transmission losses.[46] HELCO RT-4A at 11-12; see HELCO RT-1 at 46.
>
> (3) Compared to the 56 MW combined cycle Keahole project as it was originally proposed, all of the Hill/Puna repowering options were of lower generating capacity; hence the repowering options were not equivalent in capacity to Keahole CT 4/5.
>
> (4) Repowering options were not without their own shortcomings. For example, given the location of the repowering options on the east side of the Big Island, transmission upgrades and possibly another cross-island line would have had to be built

[46] Ms. Giang in HELCO RT-4, and Mr. Dizon in HELCO RT-4A, discussed the general benefits of siting generation in West Hawaii, and the specific benefits of having CT-4 and CT-5 at Keahole. The benefits of having CT-4 and CT-5 at Keahole are discussed from the perspective of HELCO's Production Manager in HELCO T-5 at 28-32.

> (these were identified in the March 1996 Contingency Plan Update, but the costs were not quantified.) Also, HELCO would have been starting the air permit process all over again, from scratch, when it appeared that HELCO had almost completed its air permit process for Keahole. The air permitting process for the repowering project would have involved its own risks.

See HELCO RT-4A at 12-13.

Subsequent events caused HELCO to stop proceeding with this contingency option. After HELCO obtained its land use authorization, the developer of a proposed IPP project, Enserch lowered its proposed prices and was willing to negotiate the remaining terms and conditions leading to a PPA. By June 1997, the terms and conditions of the PPA had been negotiated subject to Commission approval of a settlement agreement between Enserch and HELCO. At that point in time, a PPA between HELCO and Enserch's project entity (Encogen) seemed very likely. HELCO and Encogen signed a PPA on October 22, 1997. Also, on October 28, 1997, HELCO received its air permit for Keahole, and was awaiting resolution of appeals. HELCO RT-4A at 13-14.

f. Summary

In summary, the issue of whether it was reasonable for HELCO to site new generation at Keahole after HELCO was unable to obtain a site for a new generating station in West Hawaii was fully litigated in Docket No. 7048, and the Commission explicitly found that the decision was reasonable. The factors for and against the decision to site generation at Keahole were extensively considered in a contested case proceeding. See D&O 13050 at 10-12. As the Consumer Advocate stated in its testimony: "Even though it was recognized that HELCO may still experience permitting problems, the Commission ultimately approved the commitment of funds to construct CT-4 at Keahole in January 1994, generally due to the difficulty of acquiring land at the other sites and Keahole being the only alternative site to possibly meet HELCO's generation needs in 1994." CA-T-3 at 94; HELCO RT-1 at 43-44. Any attempt to relitigate this matter, after there was a full and fair opportunity to litigate the issue at the time the decision was made, would be unfair and inappropriate. See HELCO RT-1 at 43-44.

3. CDUA

In light of the urgent need for additional generation on the Big Island, and based on past experiences and reasonable expectations regarding the available procedures for obtaining a land-use entitlement, HELCO applied for an Amendment to its CDUP for the installation of CT-4 and CT-5 at the Keahole site. The complications that the Company encountered in the CDUA process were caused by circumstances beyond HELCO's reasonable control. In the face of opposition from project opponents, HELCO nevertheless succeeded in obtaining a land-use entitlement, the validity of which was ultimately affirmed in the Hawaii Supreme Court.

The history of HELCO's ultimately successful efforts to obtain the land use authorization is summarized in Appendix C to the Keahole Cost Report, and a more detailed chronology (based on the Monthly Status Reports) was submitted as HELCO-R-102. The Commission and Consumer Advocate were kept apprised of the status on a monthly basis by the reports filed pursuant to D&O 14284 in the CT-5/ST-7 docket. See HELCO RT-1 at 47.

In HELCO RT-15F, Ben Tsukazaki, Esq., of the law firm of Tsukazaki Yeh & Moore, who is a Big Island attorney concentrating in land use law, addressed assertions that HELCO should have pursued reclassification of the Keahole site, followed by rezoning ("Reclassification/Rezoning"), instead of a CDUA, as well as the reasonableness of HELCO's extensive efforts to obtain and retain the land use authorization necessary to install CT-4 and CT-5 at Keahole, and the reasonableness of the legal costs incurred in that effort. In HELCO RT-1, Mr. Warren Lee also provided information with respect to HELCO's reasons for requesting a

CDUA, as well as HELCO's expectations with respect to the length of certain delays in the land-use permitting process.

a. Land Rights Proceedings

As stated in HELCO's response to CA-IR-500(d), the Company did not pursue Reclassification/Rezoning of the Keahole site as part of its original proposal to install CT-4 and CT-5 at the Keahole Generator Station. HELCO had been granted a CDUP for the Keahole site in 1973. That CDUP had been amended on three prior occasions (i.e., in 1984, 1987, and 1988) for installing additional generating units. Thus, in 1992, HELCO sought to obtain a CDUA (which was in essence another proposed amendment of the 1973 CDUP) for CT-4 and CT-5. See HELCO RT-1 at 53; HELCO RT-15F at 13.

In 1992, HELCO estimated that Reclassification/Rezoning of the Keahole site would have delayed the project beyond 1995, when generating capacity was required. See HELCO RT-1 at 53. Mr. Warren Lee in HELCO RT-1 and Mr. Jose Dizon in HELCO RT-4A discussed the urgent need for additional generation in the 1990s.

Reclassification of the Keahole site from the State Conservation District to the Urban District would have required an accepted EIS and approval by the State Land Use Commission ("LUC"), and was expected to take at least one to two years. After reclassification was obtained, a change in the Hawaii County zoning from Open ("O") to General Industrial ("MG") would have required approval by the County Council and Mayor after review by the County Planning Department and Planning Commission. This could have taken anywhere up to five or more years. See response to CA-SIR-53(a).

Based on this, HELCO decided to obtain a CDUA – as it had successfully done before – and would consider Reclassification/Rezoning of the Keahole property after the installation of the CT-4/CT-5/ST-7 project was completed.[47] Accordingly, HELCO filed its CDUA application in August 1992. The application triggered the need for an EIS, a draft of which was submitted to the DLNR in late 1992. At that time, a relatively short time was anticipated for Board of Land and Natural Resources ("BLNR") approval and for acceptance of the EIS. See HELCO RT-1 at 47.

HELCO encountered complications with respect to obtaining its accepted Final EIS, which was denied during its thirty-day acceptance period because it did not reflect the generation contribution of PGV, an IPP which had finally come on line after the Draft EIS had been submitted. The DLNR eventually accepted HELCO's Revised Final EIS in January 1994. See HELCO RT-1 at 47-48.

At a public hearing on the CDUA held by BLNR in January 1993, a number of project opponents testified against HELCO's application and two individuals residing in the neighboring agricultural park verbally requested a contested case hearing. There were several complications and delays in scheduling a contested case hearing and in obtaining acceptance of the EIS, and in addressing numerous lawsuits and administrative proceedings related to those steps, all of which contributed to HELCO incurring unanticipated legal fees as well as other costs. See HELCO RT-1 at 48.

On June 24, 1994, the Third Circuit granted a stay on construction at Keahole, and subsequently ordered BLNR to hold a contested case hearing and reach a decision on the CDUA within 49 days of the order, subject to permissible extension by BLNR. On November 29, 1994, the chair of BLNR called for a one-year extension, with an extended decision deadline of

[47] See letter dated December 8, 1993 from Warren Lee to Keith Ahue, Chairperson, DLNR, which is included in the Revised Final EIS for the Keahole Generating Station Expansion, dated December 1993 and accepted on January 7, 1994 by DLNR; Prefiled Direct Testimony of Albert L. Lyman, filed November 17, 1995 in CDUA No. HA-487A at 25-27; HELCO RT-1 at 53-54.

December 28, 1995. Even though the process took longer than expected due to circumstances beyond HELCO's reasonable control, the Third Circuit ultimately ruled that in lieu of an approved permit, HELCO had validly obtained a "default entitlement" as of April 1996. See HELCO RT-1 at 52-53.

HELCO obtained its default entitlement as a result of BLNR's inability to garner enough votes (four out of the six members of the board) to either approve or deny the CDUA. The default entitlement enabled HELCO, by operation of law, to put its property to the use applied for. The validity of and terms and conditions inherent to a default entitlement triggered many more lawsuits and administrative proceedings over the next nine years, which were attributable to aggressive opposition to the project. As a result, there were several lengthy construction delays and additional legal and other costs were incurred. See HELCO RT-1 at 48.

KDC faulted HELCO for bringing a 1996 declaratory judgment action to confirm its default entitlement, stating that, "By bringing its own action, the Company consumed the first 16 months of its 3-year construction period [and] left only 20 months 'on the clock' remaining for the 3-year period." On the contrary, HELCO had the responsibility, if not the obligation, to defend and protect its apparent rights in litigation. The clearest indication of the reasonableness of HELCO's actions with regard to the default entitlement is that HELCO ultimately prevailed on this issue at both the Third Circuit and Hawaii Supreme Court. Abandonment of HELCO's rights would have been unreasonable. See HELCO RT-15F at 16-17.

A three-year construction deadline applies as a condition subsequent to a CDUA. See HELCO RT-15F at 15. HELCO had a reasonable basis to believe that the deadline did not apply to its default entitlement, however, given that:

(1) DLNR issued a letter to HELCO in January 1998 specifically stating that the condition did not apply;

(2) Orders and judgments had been entered in various related proceedings that lent credibility to DLNR's representations to HELCO; and

(3) There was technically no CDUP granted, as BLNR's failure to timely act upon HELCO's CDUA resulted in a default entitlement.

See HELCO RT-15F at 15.

Nonetheless, in September 2000, the Third Circuit granted a post-judgment motion by opponents to the project, imposed a stay on construction, and ruled that a three-year construction deadline condition applied to the default entitlement and that absent an extension from BLNR, the deadline had expired as of April 1999. See HELCO RT-1 at 49. HELCO responded to the September 2000 ruling by requesting an extension from BLNR, and following a contested case hearing on the matter, BLNR approved HELCO's request in March 2002. As a result, the Third Circuit lifted the stay on construction in April 2002. See HELCO RT-1 at 49.

Construction continued after the Third Circuit lifted the stay. However, project opponents challenged BLNR's construction deadline extension, arguing that BLNR had no authority to grant an extension for a deadline that had already expired. In September 2002, the Third Circuit agreed and reversed the March 2002 BLNR extension. All construction work was once again stopped. HELCO appealed this decision to the Hawaii Supreme Court in November 2002. HELCO RT-1 at 50.

HELCO took steps to reach a settlement with the opponents on this issue. While mediation efforts were ongoing, in July 2003, the Hawaii Supreme Court affirmed the validity of HELCO's default entitlement. Following this decision, settlement discussions escalated. A Settlement Agreement was executed on or about November 6, 2003 and provided, subject to satisfaction of several conditions, that HELCO would be permitted to proceed with installation of

CT-4 and CT-5, and, in the future, ST-7.[48] On November 17, 2003, HELCO resumed construction of CT-4 and CT-5. The units were installed and were put into limited commercial operation in May and June 2004, respectively. See HELCO RT-1 at 50-51.

KDC characterized the Company's participation in litigation and other proceedings that challenged the 1992 CDUA process (and the resulting default entitlement) as being unreasonable. See KDC Position Statement at 22. However, in light of DLNR's refusal to explicitly recognize the default entitlement, it was reasonable – if not obligatory – for HELCO to confirm, then defend, its land use rights in court. See HELCO RT-15F at 14. HELCO was also reasonable in attempting to obtain an extension of the construction deadline from BLNR. See HELCO RT-15F at 16. The clearest indication of the reasonableness of HELCO's actions with regard to the default entitlement is that HELCO ultimately prevailed on this issue in both the Third Circuit Court and the Hawaii Supreme Court. See HELCO RT-15F at 17.

b. Rezoning vs. CDUA

In its Position Statement, KDC challenged the reasonableness of pursuing a CDUA as opposed to seeking Reclassification/Rezoning of the Keahole site. See KDC Position Statement at 7. In short, as demonstrated in HELCO RT-15F, HELCO's decision to pursue a CDUA in the 1992 timeframe was reasonable and prudent in light of (1) the relative strengths of the CDUA process as compared to the Reclassification/Rezoning process, and (2) the circumstances faced by HELCO during that timeframe.

Reclassification/Rezoning approvals are neither more advantageous nor more permanent than a CDUA approval. See HELCO RT-15F at 12. Any approval is subject to conditions

[48] The Settlement Agreement was executed by HELCO, KDC, Ratliff, Cooper, DHHL, DOH, BLNR and DLNR. In October 2003, the BLNR conditionally approved a 19-month extension of the previous December 31, 2003 construction deadline (i.e., to July 31, 2005), but subject to court action allowing construction to proceed. HELCO RT-1 at 50.

subsequent in the interest of public health and welfare. HELCO RT-15F at 3. In fact, the CDUA process may be considered to be advantageous when compared to the Reclassification/Rezoning process for several reasons:

> (1) The CDUA process is expressly limited to a period of 180 days from the time that a completed application is accepted, which is considerably shorter than an estimated four to five years of processing time in the 1992-1997 period for a sequential Reclassification/Rezoning process.[49] In addition, under the Hawaii County Code from 1992 to 1996 (and at present), there was no maximum period in which the County Council had to take action, perhaps reflecting the Council's performance of a legislative function. See HELCO RT-15F at 10, 11.
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> (2) The CDUA process involves a single discretionary procedure, whereas the Reclassification/Rezoning process involves sequential processing and decision-making by two agencies from two different levels of government (i.e., the LUC and, assuming the LUC has approved the district reclassification, then the County Council). In addition to the greater time needed to complete both the LUC and County processes, there is an increased risk in that each is an unrelated discretionary process, and each will involve the imposition of conditions that inevitably affect the viability of a proposed development. See HELCO RT-15F at 9-11.
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> (3) Whereas the CDUA approval is susceptible to one appellate process following the single discretionary action by BLNR, the Reclassification/Rezoning process is subject to such review after each discretionary action is taken (first by the LUC, followed by the County Council), thereby being subject to two separate appellate processes in two different time frames. Without time limits at each level of the appeal process, judicial review can take several years. See HELCO RT-15F at 10, 11.

In addition to potentially lower risk and shorter processing time, the prudence of HELCO's pursuit of a CDUA is supported by the facts and circumstances faced by the Company during the early 1990s, including: (1) the backdrop of public pressure to address electric grid problems (i.e., power failures, rolling blackouts, limited capacity, increasing demand, and other problems inherent to the Big Island's grid); and (2) BLNR's previous three CDUA approvals for

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[49] The time required to reclassify and rezone the property following the November 2003 settlement was not indicative of what would have happened in 1992. The successful rezoning followed a settlement that resolved outstanding litigations contesting the right to add generation at Keahole. That settlement occurred only after the Hawaii Supreme Court confirmed HELCO's default entitlement to add generation at Keahole. All of the opponents to the project, except Waimana (which was ultimately found to be without standing), entered into the settlement agreement. HELCO RT-1 at 54-55.

additional generation facilities at Keahole. See HELCO RT-15F at 12-13.

Further, there is no reason to believe that the opponents of the project would not have opposed Reclassification/Rezoning of the site. There were two categories of opponents to adding further generation at Keahole. One group opposed the addition of any further generation, and even attacked the Company's right to maintain its existing generation at Keahole. The second group, including Waimana, opposed all efforts by HELCO to add its own generation, at least prior to the addition of generation by KCP at Kawaihae. There is no basis to assume that the opposition by either group would have disappeared or even lessened if HELCO had sought Reclassification/Rezoning of the Keahole site, instead of a CDUA. What is clear is that the opponents would have had three bites at the apple if HELCO had sought Reclassification/Rezoning of the Keahole site: once before the LUC, a second time before the County Council, and a third time before the Mayor (through his veto power). Even assuming HELCO had been successful in its attempt to rezone the site in 1992, HELCO would not have been able to avoid conditions on its use of the property. See HELCO RT-1 at 55-56.

4. Air permitting

After obtaining the land use authorization it needed to install new generation in 1996, the only remaining permit needed for the installation of generation at Keahole was the air permit. The further delays encountered in obtaining the final air permit needed to install CT-4 and CT-5 at Keahole were extraordinary, and were beyond HELCO's reasonable control. Through it all, HELCO took prudent and diligent actions to obtain the final PSD air permit, and could not have reasonably anticipated the substantial delays in the PSD air permitting process.[50] See HELCO

[50] Part of the reason for that was the unprecedented efforts of an IPP to oppose HELCO's efforts. Waimana/KCP sponsored testimony at one of HELCO's air permit hearings, appealed the air permit to the Environmental Appeals Board, helped fund KDC's participation in the CDUA proceedings and litigations, and directly opposed the Keahole CDUA in numerous administrative proceedings and

RT-1 at 39; HELCO RT-15A at 20.

Mr. Scott Seu, in HELCO RT-15A, detailed the reasons and bases for HELCO's air permitting efforts, as well as HELCO's expectations with respect to the length of certain delays in the permitting process. Mr. Jim Clary, President of Jim Clary & Associates, who is a certified consulting meteorologist and provides consulting services and training in air quality, rebutted KDC's contentions regarding air permitting in HELCO RT-15B. Additional details pertaining to HELCO's Keahole air permitting efforts are available in the Monthly Status Reports.

In short, throughout the permitting timeline, HELCO presented extensive data and air quality analyses to support its PSD application. Based on this data, HELCO received favorable regulatory agency determinations, as exhibited by the DOH's ambient air quality impact reports and the issuance of draft and final permits. On occasion, however, these agency determinations were unexpectedly called into question by the DOH, the EPA, or the EPA Environmental Appeals Board ("EAB"). See HELCO RT-15A at 15. The corresponding delays, which were unprecedented in Hawaii for a generation project,[51] were primarily due to the following events:

(1) the development and promulgation of the new state Covered Source air regulations in 1993;

(2) the DOH decision in September 1994 to incorporate new meteorological data into the CT-4/5 air quality analysis;

(3) the EPA's change in position in November 1995 regarding the use of selective catalytic reduction ("SCR") as best available control technology ("BACT");

(4) the petitions filed against the final PSD permit in November and December 1997 to the EAB, including a petition filed by KDC, and the EAB's partial remand order in November 1998;

(5) the EPA's determination in December 1999 that additional air quality data needed to be gathered to support the issuance of the air permit; and

(6) the petitions filed against the final PSD permit to the EAB in September 2001, again including a petition by KDC.

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litigations. HELCO RT-1 at 39.

[51] See HELCO RT-1 at 39.

See HELCO RT-15A at 3-4.

Based on past experiences with combustion turbine permitting, HELCO reasonably anticipated issuance of an effective Keahole PSD permit in mid-1994 when it submitted its PSD permit application submittal in January 1993. See HELCO RT-15A at 2. The reasonableness of this expectation was confirmed by the finalization in November 1993 of the new State Covered Source air regulations, which require the DOH to conditionally approve, or deny a PSD application within 12 months after receipt of a complete application. See HELCO RT-15A at 3. Notably, HELCO's judgment that the necessary permits and approvals would be obtained despite the opposition to the Keahole Project was ultimately borne out. See HELCO RT-1 at 39.

a. Promulgation of New State Covered Source Air Regulations

As a result of the state's adoption of new covered source air regulations in 1993, HELCO was required to file additional information in a Covered Source permit application for CT-4 and CT-5, and did so on February 1, 1994. Although the initial January 1993 air permit application had previously been deemed complete on June 14, 1993, the covered source permit application had to be reviewed for completeness under the new regulations. The application was again deemed complete by the DOH for PSD purposes on February 25, 1994, and for covered source purposes on May 13, 1994. See HELCO RT-15A at 4-5; HELCO RT-15B at 5-6.

b. DOH/New Meteorological Data

After finding that the application was once again complete, DOH prepared the draft permit and the Ambient Air Quality Impact Report for the Keahole Project, and a public hearing was held September 12, 1994. See HELCO RT-15A at 5; HELCO RT-15B at 6-7.

Prior to the hearing, on September 8, 1994, HELCO had submitted an application to modify the existing Keahole CT-2 PSD air permit. HELCO did not anticipate that submitting the

CT-2 permit modification application would be problematic for the CT-4/5 permit, given the use of a different meteorological data set. At that time, HELCO had worked very closely with DOH for over a year and a half in successfully justifying issuance of the draft CT-4/5 air permit with the original meteorological data set, and it was within the DOH's discretion to continue to process the Keahole CT-4/5 permit application on the basis of the initial data set. See HELCO RT-15A at 19-20.

Nonetheless, the DOH unexpectedly decided and announced at the September 12, 1994 public hearing that a second public hearing would be held to afford an opportunity for the public to review the more recent meteorological data from the CT-2 application. The impact of this decision was that DOH would need to (1) undergo technical review of a new air quality modeling analysis; (2) revise the draft permit's ambient air quality impact report; (3) reissue a draft permit; and (4) hold another public hearing. See HELCO RT-15A at 5-6; HELCO RT-15B at 6-7.

HELCO did not expect a protracted period of delay as a result of DOH's determination. Although DOH required HELCO to prepare a new ambient air quality impact analysis using the meteorological data from the CT-2 permit application, HELCO considered that this would only add several months to the CT-4/5 air permit process. See HELCO RT-15A at 20.

DOH reviewed the new data and prepared "Supplement A" to its Ambient Air Quality Impact Report. The second public hearing was held on April 10, 1995, seven months after the first public hearing. See HELCO RT-15A at 6; HELCO RT-15B at 8-9.

After the second public hearing, the DOH determined that the ambient air quality monitoring data satisfied the permitting requirements. DOH did not ask HELCO to collect any new ambient air quality data. On September 28, 1995, DOH sent its response to comments and its proposed final permit to EPA for signature. EPA did not require any additional data either, although it did change its position with respect to BACT. See HELCO RT-15B at 10.

c. EPA's Change of Position Regarding BACT

In addition to an ambient air quality impact analysis, a critical component of a PSD air permit application is an assessment of BACT. The applicant is required to determine BACT for certain emissions following the EPA methodology, and to incorporate the controls into the project. BACT for NO_X emissions proposed in the 1993 CT-4/5 PSD application was the use of water injection. In a letter to the DOH dated November 14, 1995, the EPA unexpectedly adopted the position that rather than water injection, SCR should be considered BACT for Keahole CT-4/5 when operated in combined cycle, and that the DOH could use its discretion with regard to requiring SCR for simple cycle operation. See HELCO RT-15A at 6-7.

EPA's determination that SCR should be required for Keahole CT-4/5 not only came as a surprise, but was also inconsistent with the process outlined for the MECO SCR demonstration project. MECO's Maalaea M14-16 air permits, approved by DOH and EPA in 1991 and 1992, deemed water injection as NO_X BACT, while also requiring MECO to conduct an SCR demonstration project. The permit language concerning the SCR demonstration project explicitly provided that an independent consultant was to review the SCR demonstration project final results and prepare an analysis of alternative NO_X control technologies. EPA and DOH could require use of SCR or an alternative control technology if demonstrated to be technically feasible and if supported by the results of the independent consultant's analysis.

The initial draft air permit for Keahole CT-4/5, issued in August 1994 and reviewed by EPA, contained the same NO_X BACT determination requiring water injection, subject to revision depending on the results of the Maalaea SCR demonstration project. The second Keahole draft air permit was issued in March, 1995, again with the same requirements. In November, 1995, when EPA indicated that it had adopted the position that SCR should be considered NO_X BACT for Keahole CT-4/5 when operated in combined cycle, only preliminary results from the Maalaea SCR demonstration project were available and no final determinations had been made. MECO had most recently provided DOH and EPA with preliminary data from the SCR demonstration project in a September 12, 1995 Status Report. No independent consultant had been retained and no consultant analysis had been prepared.[52]

HELCO met with the EPA to address the EPA's change in position, and the EPA suggested that HELCO "net out" of federal NO_X BACT requirements.[53] HELCO agreed with this approach, and subsequently submitted a detailed NO_X netting proposal to the DOH. HELCO's proposal was accepted by the EPA and the DOH and incorporated into the draft PSD air permit. HELCO RT-15A at 7-8.

By letter dated April 17, 1996 to the DOH, the EPA raised another concern regarding HELCO's position that the use of naphtha fuel at Keahole was BACT for sulfur dioxide ("SO_2"). However, upon HELCO's showing that the use of naphtha in CT-4 and CT-5 would be economically infeasible and should not be considered BACT for SO_2, DOH and the EPA concurred with HELCO's SO_2 BACT determination. See HELCO RT-15A at 8.

Based on the additional information submitted by HELCO in response to EPA's change in position, DOH added equipment shutdown permit conditions required by the netting for NO_X BACT. DOH updated its Ambient Air Quality Impact Report by adding Supplement B, but did not revise the dispersion modeling and background ambient air quality data contained in its

[52] See HELCO's Response, filed May 11, 2007 to KDC's Responsive Statement to Rebuttal Testimonies dated April 28, 2007, at 4-5.

[53] To net out requires that net NOx emissions increases at the Keahole facility be kept below the EPA's significant NOx emissions increase threshold upon startup of CT-4 and CT-5.

initial Ambient Air Quality Impact Report and Supplement A. See HELCO RT-15B at 11.

Although the public had an opportunity to comment on Supplement B in the third public comment period, no new comments were received regarding the air quality modeling and ambient air quality data, and DOH did not revise the dispersion modeling and background ambient air quality data contained in initial Ambient Air Quality Impact Report and Supplement A. HELCO RT-15B at 11.

The EPA's change in position on NO_X BACT impacted the project schedule. The EPA approved the final PSD air permit and the DOH issued the final permit to HELCO by letter dated October 28, 1997. Considering that the proposed final permit had first been sent to the EPA in late 1995, the EPA's unanticipated change in position on NO_x BACT in November 1995 resulted in a two-year delay. See HELCO RT-15A at 8; HELCO RT-15B at 11.

d. 1997 petitions and 1998 EAB order

Following issuance of the final Keahole PSD air permit, nine petitions were filed against the permit to the EAB in November and early December 1997. The petitions were filed by KCP, KDC, and seven private citizens. With the filing of the petitions, permit effectiveness was stayed and construction of CT-4 and CT-5 could not begin. See HELCO RT-15A at 9; HELCO RT-15B at 11.

As of 1993, no appeals had ever been filed against a utility air permit in Hawaii. In addition, HELCO, MECO and HECO had successfully obtained eight previous PSD air permits for various power plants across the islands. See HELCO RT-15A at 9.

In response to the petitions, the EAB issued an Order Denying Review in Part and Remanding in Part on November 25, 1998 ("1998 EAB Order").[54] The EAB did not find fault

[54] In re Hawaii Electric Light Co., Inc., 8 E.A.D 66 (EAB 1998), U.S. Environmental Protection Agency Environmental Appeals Board, http://www.epa.gov/eab/.

with the data submitted by HELCO, but rather, found that: (1) DOH's response to the public's comments regarding the currentness for the SO_2 and particulate matter ("PM") data were not adequate (1998 EAB Order at 101), and (2) DOH had not provided an adequate response to comments explaining why the carbon monoxide ("CO") and ozone ("O_3") data were representative (1998 EAB Order at 104). See HELCO RT-15A at 16-17.

The EAB partial remand was not expected. In HELCO's view, the air quality data used in the Keahole CT-4/5 permit application were technically sound, and had been extensively reviewed by both the DOH and the EPA. See HELCO RT-15A at 10.

HELCO worked very closely with DOH staff in December 1998 to identify acceptable air quality data to use in responding to the EAB remand. Based on discussions with DOH and a careful evaluation of all options, DOH approved HELCO's proposal for to the use of five months of data from HELCO's Huehue Substation (O_3), and State air monitoring stations at the Keahole airport (PM_{10}), Konawaena (SO_2), and Kapolei (CO). HELCO began collecting air quality data at Huehue in January 1999. A fourth public hearing was subsequently held in Kona to allow the public the opportunity to review the results of the five months of data from HELCO's Huehue Substation and the State air monitoring stations described above. See HELCO RT-15A at 11; HELCO RT-15B at 12-13.

e. 1999 EPA Air Quality Data determination

Following the fourth public hearing and comment period in October 1999, HELCO felt that all issues could be adequately addressed and the permit reissued. However, the EPA unexpectedly took the position that a full 12 months of monitoring data for SO_2, CO, O_3 and PM_{10} at the Huehue monitoring station should be collected, and recommended that a second station measuring SO_2 and PM_{10} be installed to determine the representativeness of the Huehue data. This was not expected as it was HELCO's understanding based on discussions with DOH that EPA had reviewed DOH's Supplement C before the third public comment period. By letter dated January 5, 2000, DOH concurred with EPA's position and required that HELCO collect additional air quality data. This was yet another unanticipated change of a prior DOH determination. See HELCO RT-15A at 11-12; HELCO RT-15B at 13-14.

HELCO immediately began working with DOH to obtain their approval of a second "confirmatory" air quality monitoring site for SO_2 and PM_{10}, and installed an additional air quality monitoring site at the end of Kakahiaka Street in the Kona Palisades area. HELCO collected two months of air quality monitoring data at this site, in accordance with the EPA and DOH directives. See HELCO RT-15A at 12; HELCO RT-15B at 14.

After HELCO submitted all of the additional required Huehue air quality data, DOH prepared Supplement D of its Ambient Air Quality Impact Report on December 27, 2000. See HELCO RT-15A at 13; HELCO RT-15B at 14. A fifth public hearing was held on March 6, 2001, to allow the public the opportunity to review DOH's Supplement D and the response to the fourth public comment period comments. On July 18, 2001, the EPA approved the final air permit and DOH issued the final permit to HELCO by letter dated July 25, 2001. HELCO RT-15B at 15. Considering the amount of time between the fourth and fifth public hearings, the EPA decision to require additional data in 1999 added seventeen months to the schedule. See HELCO RT-15A at 13.

f. 2001 permit issuance and appeal to EAB

The final air permit did not immediately take effect upon its issuance, as six petitions for appeal were filed at the EAB in August 2001. See HELCO RT-15A at 13; HELCO RT-15B at 15. In these petitions, the Petitioners (including KDC) raised a number of objections, including:

(1) objections to the ambient air quality data that HELCO collected for use in the revised Ambient Air Quality Impact Report based principally on the location of the monitoring station;

(2) challenges to DOH's use of the data collected for a confirmatory study;

(3) allegations that some data used in the Ambient Air Quality Impact Report were not current; and

(4) challenges that DOH improperly limited the scope of the public comment on remand.

See HELCO RT-15B at 15.

Various motions were filed on the petitions, and on November 27, 2001, the EAB denied review of the petitions on all grounds, upholding HELCO's air quality impact results. Nevertheless, the EAB petitions added three months more delay. With this ruling, the Keahole CT-4/5 PSD air permit was deemed effective. See HELCO RT-15A at 14-15.

5. Groundwater

HELCO planned to meet the operational source water needs of both the new plant and equipment as well as the existing plant by constructing its own on-site water wells. HELCO RT-15C at 22.

Since the water purity requirements for the plant equipment require treatment of the water regardless of whether the source was potable or non-potable, HELCO proceeded with seeking a non-potable on-site source as a means to secure a reliable supply, reduce costs, and not burden the County water supply system. HELCO RT-15C at 22.

Interveners challenged HELCO's ability to use the brackish groundwater from its on-site wells. As explained in Docket No. 7623, Waimana filed a petition for declaratory ruling with the BLNR requesting a ruling that BLNR was the proper body to make determinations concerning HELCO's right to use the groundwater under its Keahole site, and that HELCO did not have the right to use the groundwater under the Keahole site. HELCO RT-15C at 22.

The alleged basis for Waimana's claim was that the Keahole site, which HELCO purchased from the State, was formerly "ceded" land. However, it was not clear whether the groundwater had "ceded" property status. It was HELCO's understanding that the relationship between "ceded" land and appurtenant water was unsettled under Hawaii law. HELCO RT-15C at 22.

Due to the unclear status of the potentially "ceded" water and as a contingency to ensure a reliable source of water would be available for the project, HELCO obtained an agreement with the County Department of Water Supply for a supply of potable water. See KDC Position Statement at 21; HELCO RT-15C at 22.

Although HELCO eventually obtained the rights to the groundwater, the issue of the process to obtain the rights took a while to resolve. HELCO initially applied for a brackish water license from BLNR in 1998. That request was stalled and came up for hearing again in mid-2000, but due to uncertainty within the agency as to the proper means of processing the request, it remained unresolved for a time. Eventually, HELCO obtained a revocable water permit in December 2003, then eventually applied for the right to bid on a long-term water lease and was the successful bidder. In July 2004, HELCO executed the long-term lease with the State to use the groundwater. HELCO RT-15C at 22-23.

Both of these groundwater rights were challenged by Waimana, and the long-term lease was also challenged by another group. The appeals were denied at the Third Circuit in 2004 and 2005, respectively, and then at the Supreme Court in 2006. HELCO RT-15C at 23.

The timing of obtaining the groundwater rights did not adversely impact the schedule for installing or operating CT-4 or CT-5. HELCO RT-15C at 23; see KDC Position Statement at 12, 21.

D. COST ISSUES

1. Cost Increases

Referring to HELCO-R-1503, the total actual cost for the CT-4 and CT-5 projects (including the costs for the three Pre-PSD facilities placed in service prior to 2000) through December 31, 2006 was $117,609,535 (prior to the stipulated write down of gross plant in service of $12,888,888), or $57,737,935 higher than the estimate of $59,871,600 included in the CT-4 and CT-5 Commission applications, Docket Nos. 7048 and 7623, respectively.[55] HELCO RT-15 at 5.

The revised cost estimate for CT-4 provided in Docket No. 7048 was $35,798,200, as shown in Exhibit I to the Keahole Cost Report. The cost estimate was based on an estimated in-service date of November 1994, although HELCO was taking steps to expedite the in-service date, given the urgent need for new generation on the Big Island. (HELCO also recognized the possibility that installation might be delayed beyond November 1994). See D&O 13050, Docket No. 7048 at 12; HELCO RT-1 at 13.

The revised cost estimate for CT-5 provided in Docket No. 7623 was $24,073,400, as shown in Exhibit I to the Keahole Cost Report. The cost estimate was based on an estimated in service date of September 1995, based on anticipated receipt of the PSD/Covered Source Air permit in November 1994. (The combined cost of CT-5 and ST-7 was estimated to be $62,684,700.) See D&O 14284, Docket No. 7623 at 1; HELCO RT-1 at 13.

The final cost of CT-4 and CT-5 prior to the settlement was $117,609,535, including $67,505,579 for CT-4, and $50,103,956 for CT-5, as shown in HELCO-R-1502, page 12. The

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[55] CT-4 costs were presented in HELCO-R-405, Docket No. 7048, filed February 12, 1993, as revised by letter dated February 22, 1993. The cost estimate was included in D&O No. 13050, dated January 21, 1994. CT-5 costs were presented in HELCO-R-402, Docket No. 7623, filed July 1, 1994. The cost estimate was included in D&O No. 14284, dated September 22, 1995.

$117,609,535 includes the $7.57 million that the Commission allowed to be included in rate base in Docket No. 99-0207 (HELCO's 2000 test year rate case) for the three Pre-PSD facilities, including (1) the Shop/Warehouse Building ($972,599) completed in December 1998, (2) the new Fire Protection System ($745,548) completed in September 1999, and (3) the new Water Treatment System ($5,852,005) completed in December 1999, based on the Commission's estimate of the usefulness of these components to support the needs of the existing Keahole generating station prior to the addition of CT-4 and CT-5. See Decision and Order No. 18365 ("D&O 18365") issued February 8, 2001 in Docket No. 99-0207 at 27, 29, 31-32. Revised costs for CT-4 and CT-5, including the costs for the three Pre-PSD facilities placed in service prior to 2000, were provided by Kenneth Fong in exhibits to HELCO RT-15. HELCO RT-1 at 13-14.

2. Reasons for Cost Increases

As HELCO has explained, the cost increase was due to a number of factors, which are described in the Keahole Cost Report, and are described in detail in Appendix B (Reasons for Cost Increases) and Appendix C (CT-4 and CT-5 Background) to the cost report. Further details were provided in responses to information requests in this docket. Additional discussion was included in the rebuttal testimonies of (1) Kenneth Fong, HELCO RT-15 (reasons for cost increases), (2) Barry Nakamoto, HECO RT-15C and Guy Pasco, HELCO RT-15D (noise mitigation), (3) Anthony Koyamatsu, HELCO RT-15E (construction costs), and (4) Paul Fujioka, HELCO RT-9 (AFUDC). (Mr. Nakamoto served as the Keahole Project Manager from 1992 to 2000, Mr. Koyamatsu served as the Keahole Project Manager from 2000 to 2004 and Mr. Fong is currently serving as Project Manager. HELCO RT-1 at 14-15.)

The factors resulting in the cost increases were summarized in the September 9, 2005 transmittal letter for the Keahole Cost Report:

1. HELCO ordered the major components for CT-4 and CT-5 in 1991 and 1993, respectively, and the combustion turbine generators were delivered in 1994, in order to meet the urgent need for new generation at that time, and to help address the substantial uncertainty as to the timing and duration of the availability of the existing and planned non-fossil fuel generation provided and to be provided by non-utility generators, upon which HELCO relied for a substantial part of its firm generating capacity.

2. HELCO was not able to complete installation of CT-4 and CT-5 until 2004, however, due to the extraordinary delays encountered in obtaining the land use and air permits required to construct the combustion turbines. (HELCO was able to complete the Pre-PSD facilities that would serve both the existing Keahole generating system units and the new units, in 1998 and 1999, before obtaining the air permit.)

3. As a result of the delays in simultaneously having the required land use and air permits, HELCO incurred storage costs to store components for CT-4 and CT-5 offsite from February 1994 to February 1999 (for crated components that were relocated into the new Keahole shop/warehouse building) and from February 1994 to July 2002 (for the CT packages, lube oil coolers, generators, and exhaust silencers), and accumulated an Allowance for Funds Used During Construction ("AFUDC") on project costs, until the accumulation of AFUDC was stopped in December 1998, following the remand of the air permit. In addition, a relatively small amount of cost was incurred to refurbish some of the components after the long storage period, before they were installed.

4. Substantial costs were incurred to obtain the land use approval and air permit, and to defend the numerous Third Circuit litigations and Supreme Court appeals brought by or on account of opponents of the project seeking to overturn the permits.

5. Outside Construction costs increased for a number of reasons, as explained in Appendix B to the Keahole Cost Report. For example, additional costs were incurred due to normal escalation in the cost of outside contractor costs, since the construction work was done significantly later than had originally been projected. However, HELCO was able to minimize the renegotiation of earlier negotiated construction contracts. Some additional costs also were incurred when it became necessary to mobilize and demobilize construction crews to perform Pre-PSD work in 1998-1999, to commence construction in April 2002 when HELCO had obtained both the land use entitlement and air permit, but the Third Circuit stopped work in September 2002 under the land use permit.

6. As explained in the Keahole Engineering Services section of Appendix B, additional engineering costs (for engineering work performed by outside consultants) were incurred as a result of equipment and material replacement and retesting, providing noise abatement design and services to support the Settlement Agreement, design changes to improve operation reliability and safety, to support litigation, and other costs associated with the multiple project suspensions.

7. The increase in cost for mechanical, chemical and electrical equipment (including storage costs), as discussed in Appendix B, was due to construction delays, equipment

and material replacement and retesting, escalation, and additional materials procured to improve operational reliability and safety.

8. The increase in HELCO labor costs for the project was due primarily to costs to construct and start up the switchyard, higher training costs, additional labor hours for upkeep of equipment while in extended storage, added labor costs for successful start-up, and escalation of labor rates.

9. Substantial additional costs were incurred to meet new noise limitations imposed as a result of DOH's reinterpretation of prior policy, and Third Circuit rulings. The cost of the noise mitigation work is estimated to be $10.0 million.

10. Some additional costs were incurred as a result of the settlement agreement that resolved the various litigations and allowed installation of CT-4 and CT-5 to be completed. For example, HELCO agreed to install substantial landscaping.

3. <u>Proposed Cost Disallowances</u>

A fundamental regulatory principle is that prudently incurred costs in the provision of electric service should be recoverable from ratepayers. In the case of capital projects, the incurred costs generally include (1) the costs of planning, designing and permitting the project, (2) the costs of material and equipment incorporated in the project, (3) the costs of constructing and testing the project, and (4) AFUDC.

As indicated earlier, HELCO and the Consumer Advocate agreed to an adjustment of $12,898,000 of gross plant in service associated with the cost of the CT-4 and CT-5 units at the Keahole Generating Station, as part of their settlement of the revenue requirement issues.

Any further write down would have to be supported by a preponderance of the reliable, probative and substantial evidence in the record demonstrating that (1) actions taken by HELCO with respect to the permitting and installation of CT-4 and CT-5 were imprudent, based on the facts HELCO knew or should have known, given the circumstances as they existed at the time the actions were taken, and not based on speculation or "20-20 hindsight", and (2) such imprudent actions caused the incurrence of costs exceeding the stipulated write-off amount.

And, to the extent actions were subject to review at the time they were taken, such actions should not now be second guessed. As is discussed below, the evidence does not support any further write down of the Keahole project costs.

a. KDC's Proposed Cost Disallowances

KDC proposed a number of disallowances of costs associated with the CT-4 and CT-5 generating units at the Keahole Generating Station, including exclusion of all amounts relating to CT-5 ($50,181,116) from the Company's rate base. Although KDC's Position Statement itemized certain proposed adjustments, it did not specify a total amount.

KDC's position in its Position Statement was that the Commission should exclude certain CT-4 and CT-5 costs (approximately $55-60 million) resulting from delays and work stoppages, which it claims flow from decisions with respect to land use and air permitting alleged to have been imprudent. KDC also claimed that the Commission should exclude all costs related to CT-5 if CT-5 is not deemed to be used and useful for utility purposes. See KDC Position Statement at 43. KDC's blanket disallowances are arbitrary and unreasonable, and are not supported by reliable, probative and substantial evidence. HELCO RT-1 at 16-17.

The CT-4 and CT-5 projects have been completed and are providing essential generation services to customers. There is no question as to whether they are actually used or useful for public utility purposes, and HELCO is entitled to a reasonable opportunity to earn a fair return on its prudent investment in these facilities.

From HELCO's perspective, the proposed disallowances of other CT-4 and CT-5 costs appear to be based on speculation that these costs would not have been incurred if alternative actions had been taken (such as siting CT-4 and CT-5 at an unspecified alternative site, or seeking Reclassification/Rezoning instead of another CDUA, or not seeking to expedite the installation of new generation) and, implicitly, on claims that it was imprudent for HELCO not to have taken these alternative actions. However, HELCO's decision to site the generation at Keahole, to request a CDUA, and to attempt to expedite the addition of generation were previously reviewed by the Commission. The Commission, in its 1994 decision approving the commitment of expenditures for CT-4, found that HELCO had an urgent need for generation in the 1994-1995 time frame, recognized that permitting problems might delay CT-4, and still concluded, in light of present and foreseeable circumstances, that the location of CT-4 at Keahole was reasonable. HELCO RT-1 at 21-22.

If a different expansion option had been selected, all costs would have been different. (Some would have been substantially higher.) That is not a basis for disallowing the costs associated with the selected expansion option. HELCO RT-1 at 57-58.

b. Legal/Land Use Permitting Costs

$2,079,215 in costs associated with land use permitting were incurred for CT-4 and CT-5. The permitting work included consulting services by CH2M Hill to support the CDUA application filed in 1992 with BLNR. The permitting work also involved the preparation of the Final EIS and Revised Final EIS to support the CDUA application. Additionally, the consultant provided support for and participated in the BLNR contested case hearings and the litigation associated with permitting the project that is further described in Appendix C of the Cost Report, HELCO-1501. In addition, $6,375,608 in legal services costs were incurred for land use permitting and related litigation for Keahole CT-4 and CT-5. HELCO RT-15 at 13-14.

KDC opposed the recovery of land use permitting costs. The Consumer Advocate also proposed that certain legal costs for land use permitting and related litigation be disallowed. See CA-T-3 at 93-98; CA-101, Schedule B-8.

There was no demonstration, however, that the legal fees and other costs incurred for land use permitting were unreasonable in amount, in view of the administrative proceedings to obtain and extend the land use authorization, and the numerous appeals brought from legal actions initiated by project opponents in the Third Circuit in Kona, and in the Hawaii Supreme Court. (These proceedings are briefly summarized in Appendix C of the Keahole Cost Report, and are detailed in the Monthly Status Reports.) Nor has there been a demonstration that the costs were "imprudently" incurred. HELCO RT-1 at 57.

In reviewing the positions of KDC and the Consumer Advocate and the fee information, Mr. Tsukazaki considered the amount of fees to be reasonable in light of the duration of this matter, which extended over approximately 11 to 12 years. In addition, the facts indicate multiple administrative and litigation proceedings and a complexity of issues. The record also shows a serious degree of resistance from project opponents, as well as non-action or ambiguous action by regulators. As addressed above, it is reasonable for HELCO to have engaged in litigation and administrative proceedings to protect its entitlement. Retaining knowledgeable and highly skilled counsel in that regard was prudent, and the reasonableness of that decision and the costs thereof is supported by the outcome of such litigation and administrative proceedings, and, additionally, by a successfully structured settlement of the dispute with KDC and other interested parties. HELCO RT-15F at 17, 18.

c. **Landscaping Costs**

As shown in HELCO-R-1503, HELCO incurred $1,116,425 in costs categorized under landscaping. Of this amount, $903,403 was for additional landscaping to mitigate the visual impacts of the Keahole station, which was a condition of the Settlement Agreement. See response to CA-SIR-54. This work is in addition to the landscaping work HELCO did in 1998 as part of the grading contractor's work, which consisted of planting Norfolk pine trees, coconut palms, wiliwili trees, oleander, and areca palms, which cost HELCO $210,000. As explained in response to CA-SIR-54, the landscaping cost category also included $189,845 in costs for a security fence and $23,176 for work that was mis-categorized under landscaping, but was for relocating the CT-2 black start diesel engine (which was required to comply with the CT-4 and CT-5 air permit). HELCO RT-15 at 6-7.

The Consumer Advocate proposed that 50% of the $903,403 in landscaping costs be disallowed based on the contention that the costs for landscaping could have been contained at reduced levels if HELCO had rezoned Keahole, or if a different site had been selected, or if this cost had been "capped" in the Settlement Agreement. See CA-T-3 at 98; responses to HELCO/CA-IR-310-315. KDC also suggested that costs would have been lower if HELCO had sought Reclassification/Rezoning of the Keahole site. See KDC Position Statement at 19-20.

Speculation as to what costs would have been incurred if HELCO had requested Reclassification/Rezoning of the Keahole site (i.e., under a "what if" scenario) is not a basis for disallowing costs actually and reasonably incurred by HELCO. Mr. Lee in HELCO RT-1 and Mr. Tsukazaki in HELCO RT-15F addressed the reasons that HELCO requested a CDUA, and Mr. Lee addressed the reasons for the Settlement Agreement. Moreover, one of the LUC's conditions for the reclassification of Keahole requires HELCO to "provide additional landscaping to mitigate the visual impacts of the Keahole Generating Station, as set forth in the Landscape Concept Plan". Further, the County also required as a condition of rezoning that "Landscaping shall be included in the development plans to mitigate any potential adverse noise or visual impacts to adjacent properties". One cannot assume that these same landscaping conditions would not have applied if HELCO had rezoned the Keahole properties earlier.

HELCO RT-15 at 7-8.

The original proposal from project opponents (KDC, Ratliff, Cooper, and DHHL) in the settlement negotiations requested a process by which HELCO would use appropriate landscaping as approved by the Kona Outdoor Circle and the KDC. The Settlement Agreement provided in relevant part that:

> Visual Mitigation. HELCO will provide additional landscaping to mitigate the visual impacts of the Station, provided that HELCO, as necessary, obtains sub-leases, easements or other arrangements with owners or lessees of surrounding properties. HELCO will make a good faith effort to obtain such sub-leases, easements or arrangements as necessary and, further, will collaborate and consult with the Coalition and the Kona Outdoor Circle in developing appropriate landscaping plans, provided, however, that DHHL shall not be required to lease or otherwise provide use of its land for these purposes.

HELCO RT-15 at 8-9.

The installed landscaping was the result of that process and was jointly developed by HELCO, KDC, DHHL and the assistance of the Kona Outdoor Circle using Hawaii Design Associates as the landscaping architect. As indicated in HELCO's response to CA-SIR-54, HELCO estimated that its cost for the incremental landscaping as requested by the other parties would be about $750,000, <u>subject to final construction bids</u>, based on discussions with its landscape architect, who had previously worked with the Kona Outdoor Circle, one of the parties with whom the Settlement Agreement required HELCO to collaborate and consult in developing the landscaping plan. HELCO's actual costs for the incremental landscaping were $903,403, which is consistent with the range of HELCO's original estimate. The landscaping contractor was selected through a competitive bidding process, and the actual costs reflect the market conditions and costs of plants in the Kona area at the time. HELCO RT-15 at 9.

d. <u>Noise Mitigation Costs</u>

HELCO incurred additional costs to implement extensive noise mitigation countermeasures at Keahole to reduce the noise from the plant to meet the 45 dBA nighttime and 55 dBA daytime noise levels at all property boundaries required by the Settlement Agreement. As shown in HELCO-R-1503, the cost for the noise abatement work was $10,040,259. Mr. Barry Nakamoto in HELCO RT-15C and Mr. Guy Pasco in HELCO RT-15D address the noise mitigation work in more detail.

HELCO's acoustic approach to the planning of the project, including designing not to exceed the CDUP noise level limits and basing noise performance on DOH's receptor-based enforcement of the noise rules, was appropriate. Under the advice of HELCO's noise and engineering consultants, HELCO used computer acoustic modeling software and implemented noise countermeasures by obtaining competitive proposals to mitigate noise at the least cost. The Project complied with all applicable noise standards until 1999, when the DOH unexpectedly changed its interpretation of the Statewide Community Noise Control Rules (which were issued until 1996). As a result, further noise abatement measures installed after CT-4 and CT-5 came on line necessitated some additional construction work. See HELCO RT-15D at 4.

Claims related to the noise mitigation costs were rebutted by Mr. Barry Nakamoto in HELCO RT-15C, and Mr. Guy Pasco in HELCO RT-15D. Specifically, Mr. Nakamoto addressed the evolution of the noise standards applicable to the Keahole Generating Station, and rebutted contentions made by KDC that the generating units should have been originally designated to meet a 55/45 dBA standard, and/or that HELCO should have obtained noise easements from surrounding property owners (some of whom were actively opposed to the installation of new generation at Keahole). Mr. Pasco, a Senior Supervising Engineer in HECO's Power Supply Engineering Department, addressed the noise mitigation measures employed to meet the 55/45 dBA standard, and rebutted contentions that the cost of those measures would have been substantially lower if incorporated in the CT-4 and CT-5 project designs earlier in the process. HELCO's testimony in the CT-4 docket, Docket No. 7048 also summarized the efforts undertaken by HELCO to address noise concerns Keahole.

Despite the fact that there were no applicable state or county noise regulations in existence on or for the Big Island when the initial Keahole Power Plant design was being formulated in the 1992-1993 timeframe, the BLNR had added specific conditions on its 1987 CDUA approvals requiring HELCO to comply with a 70 dBA limit (during all periods of the day) for the plant's south and west property lines, which abutted the agricultural park. See HELCO RT-15C at 6-7. HELCO's noise consultant, Y. Ebisu & Associates ("Ebisu"), noted that these conditions were consistent with noise limits for agricultural zoned properties in the DOH noise code as it applied to Oahu at that time. HELCO RT-15C at 8. The DOH confirmed the acceptability of this 70 dBA limit for the Keahole plant during this pre-Statewide Noise Rule timeframe. See HELCO-R-15C01; HELCO RT-15C at 8.

i. HELCO's Consultants and the State Noise Code

HELCO relied on and followed the advice of its noise consultant, Ebisu, in designing the plant to comply with the 70 dBA limit. HELCO also utilized its design engineering consultant, Stone & Webster Engineering Corporation ("SWEC"), for providing technical assessments of Ebisu's recommendations, which were incorporated into the plans for the new plant and equipment. See HELCO RT-15C at 6, 14-15.

The applicable noise level for agricultural properties with residences under the State Noise Code is 70 dBA, consistent with agricultural properties.[56] Accordingly, during the initial

[56] In 1993 SWEC commented that HELCO might consider using a 55/45 dBA noise limit on the basis that if the DOH's rules regarding "Community Noise Control for Oahu" ("Oahu Noise Rules") was eventually applied to the Big Island, the agricultural lots with residences might be designated "residential" and have a 55/45 dBA limit instead of the 70 dBA limit for agriculture. SWEC was incorrect, however, with

design phase of the project, HELCO instructed its design engineers to design a facility to not exceed the 70 dBA limit along the south and west property lines consistent with Ebisu's recommendations. HELCO had budgeted for noise mitigation costs in the original design and procurement of CT-4 and CT-5 and the associated plant equipment, and authorized all necessary noise mitigation measures to be incorporated into the plant design to meet Ebisu's recommendations. See HELCO RT-15C at 9, 14.

The CTs are approximately 360 feet from the west property boundary and 560 feet from the south property boundary. HELCO RT-15C at 9. The CT packages were specified at 60 dBA at 300 feet instead of at 55 dBA at 300 feet (which was the recommended specification once ST-7 was added) because the packages procured by HELCO were already configured to 60 dBA at 300 feet as part of a negotiated purchase of five identical units from Stewart & Stevenson ("S&S").[57] As explained in HELCO's response to CA-IR-501(c), S&S accepted the 55 dBA limit for the CT generators and recommended that the units not be modified immediately, but that the units be sound tested at completion and then adjusted accordingly as necessary with additional sound mitigation measures such as retrofitted silencers, sound barriers, or walls. See HELCO RT-15C at 11.

ii. Issuance of Statewide Community Noise Control Rules

The State issued its statewide Community Noise Control rules ("Statewide Noise Rules"), HAR § 11-46, in September 1996. Under the Statewide Noise Rules, Class A zoning districts, (i.e., all areas equivalent to lands zoned residential, conservation, preservation, public space, open space, or similar type) are subject to a 55dBA daytime/45 dBA nighttime noise standard.

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respect to the State Noise Code designating the agricultural park as residential. See HELCO RT-15C at 13-14.

[57] Ebisu's noise mitigation recommendations for the ST-7 phase of the project were provided in HELCO's response to CA-IR-501(f) and were also addressed by Mr. Albert Lono Lyman in HELCO T-6, Docket No. 7623.

See HAR § 11-46; HELCO RT-15C at 16.

Upon initial review by HELCO, there was some uncertainty as to how the State might apply the new Statewide Noise Rules to the Keahole Plant. HELCO initiated engineering assessments to determine the feasibility of reducing the noise levels at the property line to comply with a 55/45 dBA standard in the event the DOH were to determine it applied to the Keahole Plant. See HELCO RT-15C at 17.

HELCO discussed how the recently-enacted Statewide Noise Rules would be applied to Keahole with DOH during the spring of 1997, and on June 16, 1997, DOH representatives informed HELCO: (1) that DOH applied the 70 dBA standard to the Keahole Power Plant; (2) that DOH found the Keahole Power Plant to be in compliance with the current noise regulations; and (3) of the process DOH would follow if a legitimate noise complaint were submitted on any of HELCO's facilities. The Company's discussions with DOH are explained in greater detail by Mr. Nakamoto HELCO RT-15C at 17-18.

In its initial Third Circuit pleadings in Civil No. 97-017K, DOH maintained that the noise pollution limits for the Keahole Power Plant were not 55 dBA daytime/45 dBA nighttime for the conservation zoned land on which the plant was located (i.e., the emitter site), and that DOH would take noise measurements at the point of the noise impact (i.e., the receptor site) and measure compliance with regard to the noise standard applicable to the classification of that receptor site. See HELCO RT-15C at 18.

DOH also conducted noise inspections of the Keahole Power Plant in this timeframe, and remarked that no violations were noted. See HELCO-R-15C02. These findings were consistent with DOH's interpretation of the noise rules, as conveyed to HELCO's representatives at the June 16, 1997 meeting. DOH measured the noise levels at the receptor sites. See HELCO RT-

15C at 18-19.

It was reasonable for HELCO to rely upon the guidance provided by the DOH. The DOH is the agency responsible for interpreting and enforcing the noise rules. Thus, under the recommendation of Dr. Bruce Anderson, then Deputy Director at DOH, HELCO sought and received the guidance of Mr. Jerry Haruno in his capacity as the Program Manager for DOH's Noise Branch. See HELCO RT-15C at 19.

iii. Change in DOH's Interpretation of Noise Rules

The DOH unexpectedly changed its interpretation of its noise rules in February 1999, stating that the noise level standards for the emitter site would determine the applicable noise level, and that such measurements would be taken at the boundary line or beyond the property line of the emitter site. Under the DOH's sudden new interpretation, the noise limits for the Keahole Plant would now be 55 dBA daytime/45 dBA nighttime along all property lines, instead of 70 dBA on the east, south and west, as under the previous DOH interpretation. See HELCO RT-15C at 19-20.

HELCO challenged the constitutionality of the noise rules as newly interpreted by DOH. In March 1999, the Third Circuit ruled that the noise rules were not invalid as generally applied, and that the 55 dBA daytime/45 dBA nighttime standard applied to conservation land. HELCO then appealed the ruling to the Hawaii Supreme Court. See HELCO RT-15C at 20.

The DOH eventually enforced the new interpretation of the noise rules at Keahole in June 2002 (over three years after the court's ruling) in response to a complaint from the occupant of a neighboring lot, and found noise levels to be slightly above the 45 dBA limit along the west property line at night. In response, HELCO applied for and received a noise permit (which allowed exceedances while the Company worked toward resolving the noise issues) and initiated design engineering assessments for meeting the 55/45 dBA standard along its property lines.[58] See HELCO RT-15C at 20. HELCO's Final Cost Report details the noise mitigation measures that were necessary to meet the emitter-based 55 dBA daytime/45 dBA nighttime noise limits for conservation land. See Keahole Cost Report, Appendix A at 10-12, and Appendix B at 14-15.

By applying for the noise permit and taking action to implement noise mitigation measures, HELCO was not admitting that it should have known that the Keahole plant was subject to the 55/45 dBA noise standard. To the contrary, HELCO noted in its noise application that the submittal "should not be considered a waiver of HELCO's rights or deemed an admission that these regulations are applicable or legal." See HELCO RT-15C at 20-21.

When construction resumed after negotiation of the 2003 Settlement Agreement, some of the raw materials for the noise abatement equipment were in storage on the mainland, and it was going to take time for the suppliers to gear up and resume factory fabrication and delivery activities. The CT-4 and CT-5 construction was therefore restarted without the noise abatement equipment, with priority to place critical generation assets into service and a plan to perform a phased retrofit of the noise abatement equipment after all components were delivered on site. See HELCO RT-15D at 5.

This plan was successful in that CT-4 was able to go into commercial service on May 25, 2004, and CT-5 about a month later on June 30, 2004. While the units were running, construction of most of the noise abatement structures, foundations, and support equipment was accomplished. Each unit was shut down later in 2004 to allow retrofit of components that could not be installed with the units running. See HELCO RT-15D at 5.

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[58] The engineering assessments now pertained not only to the new plant and equipment for the CT- 4/CT-5/ST-7 project, but to the existing plant equipment and operations as well. See HELCO RT-15C at 20-21.

iv. **Disallowance Claims**

KDC criticized HELCO for not requiring certain noise mitigation measures at the time the CTs were purchased. See KDC Position Statement at 13. However, lower cost low-noise features could not have instead been originally provided by the equipment manufacturers at the time of purchase, eliminating the later retrofit and modification effort. The 55 dBA daytime and 45 dBA nighttime property boundary noise level requirements are at the extreme low end of the acoustic performance range for utility generation equipment. Considerable countermeasures and engineering controls were utilized to achieve the 55/45 dBA performance of this machinery. If these acoustic requirements had been included in the original purchase, the equipment manufacturers would have had to utilize the same custom retrofit techniques ultimately carried out by HELCO. See HELCO RT-15D at 2.

KDC also suggested that HELCO should have taken certain other steps early in the project, such as establishing additional buffer zones or obtaining noise easements, to reduce noise mitigation costs. See KDC Position Statement at 13. However, when HELCO designed the project, extensive measures such as additional buffer zones or noise easements were not necessary for compliance with the applicable noise limits. Compliance was determined in accordance with how DOH was interpreting and enforcing the rules at that time. It was not until 1999, well after project design was complete and the equipment had been ordered, that DOH changed its enforcement policy. By that point, it was not reasonable to expect that the adjacent land owners, such as DHHL and Agricultural Park tenants (some of whom were active opponents of the project for reasons not limited to noise), would grant or cooperate in the granting of noise easements to HELCO. See HELCO RT-15C at 11-13.

Although HELCO had expressed an interest to the State of Hawaii in additional State land to serve as a buffer zone, HELCO never stated that the buffer zones were necessary to comply with the 70 dBA limits, and HELCO's noise consultant made no such determination. HELCO's position with respect to buffer zones was discussed in greater detail by Mr. Albert Lono Lyman in HELCO T-6, Docket No. 7623 at 16. See HELCO RT-15C at 11-13.

e. AFUDC

As shown in HELCO R-1503, the AFUDC cost for CT-4 and CT-5 was $21,661,087, or $16,347,987 higher than the amount estimated in the CT-4 and CT-5 dockets.[59] See HELCO RT-9B at 21; HELCO RT-15 at 15. The factors impacting the level of AFUDC associated with the permitting and installation of CT-4 and CT-5 are: (1) the AFUDC rate, (2) capital expenditures associated with the project and (3) the duration of the project. HELCO RT-9B at 11-12.

As a result of stopping AFUDC in December 1998, shareholders have borne the entire carrying costs of the construction work in progress from December 1998 until components were completed and placed in service. The foregone AFUDC is estimated to be $52.6 million.

Based on the results of settlement negotiations, AFUDC for CT-4 and CT-5 has been resolved, subject to Commission approval. Prior to reaching settlement, there was an issue with the Consumer Advocate concerning the amount of AFUDC for CT-4 and CT-5, as adjusted to reflect the Keahole adjustment. See HELCO RT-1; HELCO RT-9 at 15.

Although the total amount of AFUDC applied to CT-4 and CT-5 is higher than what one would expect for such a project under a normal construction schedule, the recorded AFUDC was

[59] The original cost estimate for CT-4 included in the D&O approving the commitment of expenditures was $35,798,200, which included $2,710,000 of AFUDC. The original cost estimate for CT-5 included in the D&O approving the commitment of expenditures was $24,073,400, which included $2,602,900 of AFUDC. The total estimate for CT-4 and CT-5 was $59,871,600. HELCO RT-9B at 5. The $7,570,152 already approved by the Commission to be included in rate base includes $1,497,928 of AFUDC. See HELCO-R-905; HELCO RT-9 at 16-17.

nevertheless actually incurred, and the amount of AFUDC is reasonable given the length of project delays, which were externally imposed and were beyond the control of HELCO's management. HELCO needed to proceed with the project and tried its best to obtain the necessary permits to construct the units on a timely basis. Various witnesses address what the Company had known at the time the project was proceeding. Mr. Scott Seu, in HELCO RT-15A, and Mr. James Clary in HELCO RT-15B, addressed HELCO's expectations with respect to completing the air permitting process. Mr. Barry Nakamoto, in HELCO RT-15C, addressed HELCO's plans to install certain Pre-PSD facilities at Keahole if the CDUA process was completed before the PSD air permit was obtained. Mr. Warren Lee, in HELCO RT-1, and Mr. Ben Tsukazaki, in HELCO RT-15F, addressed the CDUA process. HELCO RT-9A at 19.

The various aspects of HELCO's AFUDC recovery are addressed by several witnesses in HELCO's rebuttal testimony. In HELCO RT-9A, Ms. Patsy Nanbu, HECO's Controller, addressed HELCO and its affiliates' application of its accounting policies and procedures for AFUDC, including HELCO's application in relation to the National Association of Regulatory Utility Commissioners ("NARUC") Interpretation No. 83, and background with respect to the Commission's review of a utility's commitment of expenditures pursuant to paragraph 2.3.g.2 of General Order No. 7 ("Rule 2.3.g.2"). Mr. Paul Fujioka, in HELCO RT-9, provided the Company's recorded AFUDC as of December 31, 2006, and the Company's calculation of AFUDC foregone as a result of suspending AFUDC in December 1998. Proposals to disallow AFUDC were rebutted by Michael Adams, Managing Director of the Energy Practice of Navigant Consulting, Inc., in HELCO RT-9B. The higher-than-expected amount of AFUDC did not result from a misapplication of HELCO's accounting policies and procedures with respect to AFUDC. See HELCO RT-9A at 20-21; HELCO RT-9B at 6.

In its direct testimonies, the Consumer Advocate proposed to disallow AFUDC in the approximate amounts of $9.1 million for CT-4 and $5.3 million for CT-5. (The Consumer Advocate's proposed amount of AFUDC was $7,253,860.) The Consumer Advocate arrived at its proposed reduction by (1) delaying the start of AFUDC accrual until January 1, 1994, when the Commission issued its decision and order approving the commitment of funds for CT-4, instead of starting AFUDC when capital expenditures actually commenced for CT-4 in June 1991 and in July 1993 for CT-5; and (2) stopping the accrual during periods of significant project delays, which the Consumer Advocate identified as between October 1994 through July 1997. See CA-T-3 at 53, as revised by HELCO/CA-IR-304; HELCO-R-906 at 1-3; HELCO RT-9 at 17-18; HELCO RT-1 at 15.

As explained in HELCO RT-9A and HELCO RT-9B, however, the proposed adjustment was inappropriate in that it did not: (1) commence AFUDC accrual once work had commenced on a planned progressive basis; (2) continue to accrue AFUDC through certain project delays caused by external factors beyond the Company's reasonable control; or (3) consider the $52.6 million of AFUDC that could have been accrued during later periods of construction if HELCO had not voluntarily ceased AFUDC capitalization on December 1, 1998. HELCO RT-9A at 7-8.

i. Definition of AFUDC

AFUDC is an accounting procedure for capitalizing the cost of investor-supplied funds used to finance construction projects during the construction period. See HELCO RT-9A; HELCO RT-9B at 6. The NARUC Uniform System of Accounts ("USOA") for Electric and Gas Utilities describes AFUDC as the net cost for the period of funds used for construction purposes. See HELCO-9A01. A more rigorous definition of AFUDC was provided by Ms. Patsy Nanbu in HELCO RT-9A at 2-6.

AFUDC-related costs encompass costs for planning, designing and permitting construction work. See HELCO RT-9A at 4-5. The inclusion of such costs in AFUDC is supported by Statement of Financial Accounting Standards ("SFAS") No. 34, Capitalization of Interest Cost, which indicates that the cost of activities qualifying for interest capitalization should be construed broadly: "[I]t includes administrative and technical activities during the pre-construction stage . . . [as well as] activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labor disputes, or litigation." SFAS No. 34, ¶17; HELCO RT-9A at 5-6.

ii. AFUDC Policy

HELCO has a written policy regarding the capitalization of AFUDC, which commences when expenditures for a project begin on a "planned progressive basis" (i.e. without delay, except for the delays that are inherent in the asset acquisition process such as the ordering, purchasing and delivering of long lead time material, and delays due to permitting and external approval processes). The application of AFUDC begins after a project is formally approved by HELCO's management, and engineering charges recorded against the project are classified as construction work in progress ("CWIP"). See HELCO RT-9A at 2; HELCO RT-9B at 6, 17.

After the initial application, AFUDC is applied every month until the capital project is completed, or until the project is delayed at management's discretion, or is abandoned. In the case of a project delayed at management's discretion, AFUDC is stopped at the point of delay, and is resumed when the project is re-activated. See HELCO RT-9A at 2-3. Unlike periods of discretionary delay, it is appropriate to continue applying AFUDC during periods of delay caused by external factors and events beyond management's control. See HELCO RT-9A at 3. Under unusual circumstances, however, HELCO's AFUDC policy allowed for the stopping and starting of AFUDC as deemed appropriate by management on a case-by-case basis. See HELCO RT-9A at 16; HELCO RT-9B at 17.

iii. Application of AFUDC Policy to Keahole Project

HELCO's $21,661,087 of AFUDC accrued from June 1991 thru December 1, 1998 for CT-4, and from July 1993 thru December 1, 1998 for CT-5. See HELCO's response to CA-IR-190; HELCO RT-9B at 17-18. As discussed in HELCO RT-9A and HELCO RT-9B, these accruals were in accordance with HELCO's existing policies, and were also consistent with standards espoused by NARUC, the Federal Energy Regulatory Commission ("FERC"), and the Financial Accounting Standards Board ("FASB"). See HELCO RT-9A at 8-9, 21; HELCO RT-9B at 9-11, 16.

The accrual AFUDC associated with the Project began when work commenced on the planning for the project – prior to HELCO's receipt of the Commission's orders approving the commitment of expenditures. As stated above, the Company's AFUDC policy requires the accrual of AFUDC once work has commenced on a project on a planned progressive basis. See HELCO RT-9B at 7, 13. HELCO's commencement of AFUDC accrual was prudent and in accordance with Company policy, the reasonableness of which is supported by the following:

(1) Rather than requiring that the application of AFUDC begin only after receiving a Commission decision and order approving the project, NARUC Interpretation No. 83 states that AFUDC "may be capitalized starting from the date that construction costs are continuously incurred on a planned progressive basis." See HELCO RT-9A at 9;

(2) HELCO had a reasonable expectation, based upon past experiences, that the necessary approvals would be received in a timely manner. See HELCO RT-9A at 9; HELCO RT-9B at 7;

(3) Such capitalization was in accordance with the long-standing practice in Hawaii and consistent with past practices which the Company has been allowed to follow. See HELCO RT-9B at 16;

(4) Rule 2.3.g.2 (under which HELCO sought Commission approval for the commitment of funds) contemplates the inclusion in rate base of capital expenditures incurred "prior to the commencement of construction or commitment of expenditure . . .

." See HELCO RT-9A at 12-14; and

(5) The accrual was consistent with USOA Utility Plant Instruction No. 3, Components of Construction Cost (provided in HELCO-R-9A01), which states that "construction costs" include engineering and supervision costs as well as costs related to engineering services paid to others to "plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work." See HELCO RT-9A at 14-15.

HELCO acknowledges that there have been significant interruptions in the construction schedule for CT-4 and CT-5. Nevertheless, as explained in greater detail at pages 15-20 of HELCO RT-9A, continuing to apply AFUDC during those periods of significant interruption was reasonable for three reasons:

(1) Because the project delays were caused by external factors beyond HELCO's reasonable control, the status of the construction effort was within the meaning of "planned progressive basis";

(2) Continuing to accrue AFUDC during periods of project delays due to external factors was in line with NARUC Interpretation No. 83, Federal Power Commission guidelines with respect to the application of AFUDC and SFAS No. 34; and

(3) AFUDC needed to be accrued in order to accurately reflect the cost of investor supplied funds used in the project.

See HELCO RT-9A at 17.

Prior to December 1, 1998, the policies, facts and circumstances surrounding the Keahole Project did not warrant the suspension of AFUDC. See HELCO RT-9A at 14-16, 18; HELCO RT-9B at 8-9. There had been other projects where there had been delays due to permitting, and AFUDC was accrued during the delay. See HELCO RT-9A at 21. In addition, all parties (as well as the Commission) agreed with the need for the additional generation capacity. See HELCO RT-9B at 16. The need, urgency for additional generation on the Big Island, and reasons for pursing the project for the benefit of the ratepayers, are addressed in Part B, supra.

Moreover, HELCO reasonably expected at the time to complete the CDUA process within a year, given that the Final EIS had already been accepted, and there was a limited time frame within which the BLNR was required to act on the application. The further delays encountered in obtaining the final air permit needed to install CT-4 and CT-5 at Keahole were extraordinary, and were beyond HELCO's reasonable control. HELCO took prudent and diligent actions to obtain the final PSD air permit, and HELCO could not have reasonably anticipated the substantial delays in the PSD air permit process. See HELCO RT-9A at 19.

iv. Cessation of AFUDC Capitalization

As explained above, HELCO's management had discretion to suspend AFUDC accrual under unusual circumstances. See HELCO RT-9A at 16; HELCO RT-9B at 17. Consistent with this policy, HELCO voluntarily stopped capitalizing AFUDC on the Projects on December 1, 1998, as a result of the EAB remand of the PSD permit in late November 1998 (which meant further extended delays in the project schedule). Notably, upon receipt of the PSD permit, HELCO did not re-activate AFUDC on the Project, out of concern for the overall cost of the project. See HELCO RT-9A at 14-16; HELCO RT-9B at 8-9. The Company could have been entitled to an additional \$52.6 million of AFUDC if the accrual had continued through December 2004.[60] See HELCO RT-9 at 20; HELCO RT-9B at 18, 22.

v. Summary

It would be inappropriate to rely upon 20-20 hindsight to make judgment calls as to what HELCO's management did or should have known during the permitting and installation process. HELCO RT-9A at 19. The Company has documented its actions and made a good faith effort to

[60] In his direct testimony, the Consumer Advocate's witness, Mr. Carver, commented on the amount of additional AFUDC the Company would have charged to the Keahole project absent the suspension of AFUDC in December 1998. The amount of AFUDC forgone and costs borne by the shareholders was initially calculated by HELCO to be \$39.7 million. See HELCO-1501 at 97-98. Mr. Carver determined, however, that the Company's calculation of the \$39.7 million of AFUDC foregone was in error, and indicated that the correct amount should be \$52.6 million. See CA-T-3 at 80. Mr. Carver is correct in this respect. HELCO's calculation of the amount of AFUDC foregone, as submitted in HELCO-1501 at 97-98, was in error. See HELCO RT-9 at 20. The correct amount is \$52.6 million, as shown in HELCO-R-907.

bring the needed capacity online when needed. See HELCO RT-9B at 16-17.

The mere fact that actual AFUDC charges were greater than original estimated levels does not mean that the AFUDC was imprudently accrued. In light of the delays experienced during the permitting and installation of the units, the Company was prudent in continuing to accrue AFUDC until it conservatively stopped the accrual as of December 1, 1998. Indeed, alternative AFUDC calculations performed by Mr. Michael Adams in HELCO RT-9B confirm that HELCO has been conservative with regards to the accrual of AFUDC for CT-4 and CT-5, and that the Company's actions were justified. See HELCO RT-9B at 12, 17-22.

f. Land Rezoning

The average amount of land rezoning costs in the 2006 test year rate base is $1,958,392. See CA-101, Schedule B-8; HELCO RT-1 at 16. Prior to the settlement, in CA-T-3 at 100, Mr. Carver also recommended that land rezoning costs be excluded from the installed cost of CT-4 and CT-5. The average amount in the 2006 test year rate base is $979,196. See CA-101, Schedule B-8. Mr. Carver took the position that the recovery of such costs would have been more appropriately addressed upon HELCO's application to include the costs of ST-7 in rate base. See CA-T-3 at 100. As a result of the settlement, these costs are included in the rate base amounts stipulated to by HELCO and the Consumer Advocate.

The rezoning costs are listed as a separate component of rate base, and are not listed as part of the installed cost of CT-4 and CT-5. Filing for rezoning was a condition of the CDUA extension and of the settlement agreement that allowed CT-4 and CT-5 to be completed. Now that rezoning is complete, the costs are properly included in rate base. If the costs were not included in rate base at this time on the theory that they exclusively relate to ST-7, then the costs should accrue AFUDC until ST-7 goes into service. See HELCO RT-1 at 22, 58.

IV. ACT 162

A. INTRODUCTION

Order No. 22903 added two issues to this docket, including (1) whether HELCO's ECAC complies with the requirements of Act 162,[61] and (2) whether the Commission should adopt, modify, or decline to adopt in whole or in part, the standards for time-based metering and communications articulated in section 111(d)(14) of PURPA, as amended by EPACT (16 U.S.C. § 2621(d)(14)).

As discussed further below, HELCO's ECAC complies with the requirements of Act 162, and the Consumer Advocate agrees that HELCO's ECAC complies with Act 162. HELCO submitted the testimony of its consultants, Jeff D. Makholm, Ph.D (in HELCO ST-23) concerning energy cost adjustment clauses and Eugene T. Meehan (in HELCO ST-24) concerning fuel hedging, in addition to the testimony of HELCO/HECO employees. (The professional qualifications of these witnesses were submitted as HELCO S-2300 and HELCO S-2400, respectively.)

In summary, the Company selected a highly qualified consultant, National Economic Research Associates, Inc. ("NERA"), to provide assistance in evaluating the extent to which

[61] On June 2, 2006, the Governor of Hawaii signed into law Act 162, which amends Section 269-16 of the Hawaii Revised Statutes. Act 162, in part, states the following:

Any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:

(1) Fairly share the risk of fuel cost changes between the public utility and its customers;
(2) Provide the public utility with sufficient incentive to reasonably manage or lower it fuel costs and encourage greater use of renewable energy;
(3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
(4) Preserve, to the extent reasonably possible, the public utility's financial integrity; and
(5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

HECO, HELCO and MECO ("the Companies") currently comply with the requirements of Act 162. The consultant's final report was received on December 28, 2006 and was submitted to the Commission on December 29, 2006. HELCO ST-22 at 2-3.

The current level of ECAC fuel price risk sharing is appropriate, and no change is necessary to the current ECAC risk sharing approach. HELCO ST-22 at 3.

The ECAC does not necessarily pass 100% of any change in fuel expenses to ratepayers. HELCO's ability to recover its fuel expenses is subject to an efficiency factor, which measures how efficiently HELCO converts fuel energy into electrical energy. If HELCO cannot meet the efficiency factor embedded in the ECAC, it recovers only a portion of its fuel expenses. Thus, HELCO is already at risk for the non-recovery of some portion of fuel expense and this risk profile is inherent in the currently employed ECAC mechanism. HELCO ST-22 at 3.

The risk associated with meeting the efficiency factor is one that HELCO can address through the overhaul and maintenance of its generating units and unit commitment schedule among others. Thus, it is reasonable for the Commission to hold the Company responsible for not meeting the efficiency standard and for its fuel expenses to be subject to the risk of non-recovery as a result. HELCO ST-22 at 3-4.

However, fuel prices are subject to market forces and geopolitical events that HELCO cannot control. A risk sharing mechanism that penalizes the Company because prices increase above an expected base price, even one that provides a symmetric positive incentive when prices are below the base, holds the Company financially responsible for events beyond its control. Such a risk sharing mechanism would place the Company in an untenable financial position, for which it is not compensated. HELCO ST-22 at 3-4.

HELCO's investors view the Company's existing ECAC mechanism favorably because it significantly reduces the Company's business risks. Dependence on imported fuel oil and the associated fuel price fluctuation are significant risks to the Company. The monthly revenue adjustment for fuel and purchased energy price changes results in timely recovery of fuel oil and purchased energy costs which significantly reduces the business risk profile. Thus, the existing ECAC has a positive credit quality impact. HELCO ST-18 at 2.

In its credit assessment of HELCO's parent company, Hawaiian Electric Company, Inc. ("HECO") , Standard and Poor's ("S&P") has in the past cited "an excellent fuel adjustment clause" as strengthening credit quality in part offsetting "reliance on fuel oil", "significant purchased power obligations", and "high prices" which weaken credit quality. HELCO ST-18 at 3.

Act 162 has resulted in a change in investor concerns relating to the Company's fuel and purchased power expenses. The Company's investors are clearly concerned by the legislative action. In its credit assessment of HECO dated November 22, 2006, S&P stated in part:

> Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to fuel-adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory business profile.

There are other investor risks associated with fuel and purchased power. The Company has significant purchased power obligations which are considered in evaluations of HELCO's credit. The reliance on purchased power creates debt-like obligations which are of concern to investors. Further there have been changes in the accounting treatment of the purchased power obligations and there is uncertainty as to how these changes may impact investor views of these obligations. HELCO ST-18 at 3.

In addition, the Company is exposed to financial variability due to changes in fuel efficiency. In a rate case proceeding, fuel expense is established based on fuel efficiency factors which are embedded in base electric rates. When actual heat rates are lower (better) than the heat rates embedded in base rates, fuel expense is lower and returns to shareholders are higher. When actual heat rates are higher (worse) than the heat rates embedded in base rates, fuel expense is higher and returns to shareholders are lower. This gives management incentive to optimize the generation dispatch and to maintain and operate the Company-owned generation to maximize fuel efficiency. HELCO ST-18 at 3-4.

Further, the Company bears the costs or enjoys the benefits from cost savings resulting from changes in the carrying costs of fuel inventory. The cost of fuel inventory fluctuates as fuel prices fluctuate. Higher fuel prices result in higher inventory cost and higher costs of carrying inventory which reduces returns to shareholders. Conversely, lower fuel prices result in lower inventory cost and lower costs of carrying inventory which contribute to shareholder returns. There is not much near-term management control over these carrying costs since inventory volumes are constrained by operational requirements and inventory price is determined by the indexed fuel prices embedded in long-term fuel purchase contracts. However, since the absolute amounts of inventory carrying costs are relatively small, this risk is not viewed as a significant business risk from an investor's perspective. HELCO ST-18 at 4.

Although dependence on imported fuel oil increases business risks, the existing ECAC mechanism significantly mitigates this risk. The risks associated with changes in the fuel inventory carrying costs are generally not significant from an investor's perspective and investors do earn a return on the fuel inventory included in rate base. HELCO ST-18 at 4-5.

HELCO has plans to explore ways to mitigate the impact of fuel price volatility on customers. Mr. Makholm in HELCO ST-23 identified two rate smoothing alternatives, budget billing and fixed rate billing. HELCO will explore an optional revenue neutral budget billing rate schedule for residential and Schedule G customers. In addition, HELCO will submit to the Commission, within 12 months from the date of the Commission's final decision and order ("D&O") in this docket, a pilot budget billing program for its review. HELCO RT-22 at 7.

In addition, for the reasons discussed further below, it is not necessary for the Commission to adopt the EPACT 2005 time-based rates standards.

B. HELCO'S ECAC COMPLIES WITH ACT 162

1. Fuel Adjustment Clauses

Dr. Makholm presented written testimony in HELCO ST-23 concerning fuel adjustment clauses. Fuel adjustment clause ("FAC") mechanisms (and other cost-adjustment mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. By providing timely cost recovery for power costs, the amount of time between rate cases—called "regulatory lag"—can increase. Dr. Makholm stated that the three classic reasons for an FAC include:

1. The purchased item (most commonly fuel) is outside the control of the buying utility.
2. The item is a significant or large component of the utility's total operating costs.
3. The cost changes with respect to that item can be volatile and unpredictable.

It is not necessary that individual cost items be large, volatile and unpredictable to qualify for FAC treatment. An effective FAC covers all purchased energy costs, including renewable sources, on an equal footing. HELCO ST-23 at 4.

With respect to the first reason for an FAC, utilities procure fuel from markets and would normally not have the ability to control the price set in those markets. The 1991 National

Regulatory Research Institute ("NRRI") Report notes that "[u]nless a utility is vertically integrated so that it owns the fuel source (whether it is the coal mine, gas well, or others), it is unlikely that the utility can exert much control over the cost of the fuel." Moreover, the utility does not normally have the ability to control its customers' demand. It must procure the fuel and purchased power that are needed to meet customer demand as part of its obligation to serve. HELCO ST-23 at 4-5.

The utility has an obligation to procure its fuel and purchased power from the energy markets in a prudent manner. The NRRI Report notes that the utility is not "excused from hard-nosed, tough bargaining" and goes on to explain that state public utility commissions often hold utilities to a standard of prudent care in negotiating fuel contracts before allowing the cost to flow through a fuel adjustment or purchased gas adjustment clause. HELCO ST-23 at 5.

Given prudent management, if certain costs (called "exogenous costs") are not within the control of the utility, the pursuit of economic efficiency calls for no penalty or gain to be borne by the utility as a result of changing market conditions. Exogenous cost changes represent any change in the cost of the firm—up or down—that is beyond the control of the firm. In a competitive industry, if these costs were required to provide a service, cost changes would alter the long run marginal and average cost curves of the industry and would directly affect the market price prevailing in the industry. Because exogenous costs are not under the control of the firm, passing such cost changes through to customers automatically cannot affect the incentive of the firm to behave efficiently or the market price standard to which regulated policies aspire. The pass-through of exogenous costs permits the regulated firm's prices to reflect market conditions (for the prices of its inputs) in just the way that input cost changes affect prices in unregulated, competitive markets, while providing a market price signal to customers. HELCO

ST-23 at 5.

With respect to the second reason for a FAC, Dr. Makholm stated that fuel and purchased power costs continue to be a significant component of a utility's total operating costs. For all major investor-owned utilities ("IOUs") in the United States, the average proportion of fuel and net purchased power relative to total operating expenses ranged from 35.8 to 54.3 percent during the 1992 to 2005 period. Total fuel and net purchased power averaged 40.2 percent for the 1992 to 2005 period. The continued high proportion of fuel and purchased power costs relative to total operating costs shows that there is a continuing role for FACs as a tool for timely recovery of fuel and purchased power costs. HECO's (including HELCO) consolidated fuel and purchased power expenditures represented about 66.8 percent of expenses in 2005, up from 64.1 percent in 2004 and 62.0 percent in 2003. HELCO ST-23 at 5.

With respect to the third reason for a FAC, Dr. Makholm stated that changes in fuel and purchased power costs can be volatile and unpredictable. Although HELCO is isolated from the wholesale electricity and natural gas markets, its primary source of fuel and purchased power expenses are dependent upon the market price for oil, which constitutes about 78.1 percent of HELCO's fuel mix. HELCO ST-23 at 7.

Dr. Makholm stated that state commissions continue to cite the unpredictable nature of fuel and purchased power costs that, if unaccounted for, would leave the utility to bear the burden and financial risk of volatility. For example, the Louisiana Public Service Commission states that the "Fuel Adjustment Clause mechanism...has been established due to the materiality and historical and potential volatility of these costs." HELCO ST-23 at 8.

A utility must serve its customers under all weather and energy market conditions and therefore must purchase fuel and power to satisfy demand during peak periods during the year.

Recent history has shown that events outside a utility's control can increase the volatility of oil, purchased power and other fuel prices. HELCO ST-23 at 8.

Dr. Makholm stated that FACs are prevalent throughout the U.S. Of the 32 traditionally regulated states, only Utah and Vermont lack FACs. Many states have instituted state-wide FAC mechanisms available to all electric (or gas) utilities. Some states have dealt with each utility on a case-by-case basis, which has led to inconsistencies across utilities within these states regarding power cost adjustments. In Hawaii, each of the utilities operate under a similar fuel clause, the ECAC. HELCO ST-23 at 8.

FACs were initially established as a response to specific shocks, such as high coal prices following World War I and inflation following World War II. By the late 1950s, FACs were commonplace, albeit infrequently used for actual rate changes due to relatively stable input costs. The OPEC oil crisis of 1972-73, however, put FACs back in the spotlight. Following the energy crisis of 1972-73, state commissions paid increased attention to FACs. In terms of FAC design issues, the focus of at least 29 states was on uniformity so that all utilities in a state would be able to change their fuel rates using the same approach. By 1990, forty jurisdictions had long-standing FACs in place. In Hawaii, an oil cost recovery charge has been in place since at least the 1920s. HELCO ST-23 at 9-10.

2. HELCO's ECAC

Dr. Makholm examined and presented testimony on HELCO's ECAC. HELCO's fuel and purchased power mechanism follows the same cost recovery formula as its larger affiliate, HECO, whose ECAC includes both fuel and purchased power costs. It computes the monthly weighted average of the various fuel and purchased power costs based on fuel mix, which is then converted to a rate for customers based on the estimated MWh sales for the month. The ECAC uses an efficiency factor (measured in MBtu/kWh) to calculate the conversion between the MBtu of fuel purchased and the amount of kWhs generated. The ECAC contains a quarterly reconciliation for the previous quarter's actual experienced fuel and purchased power expenses on a per kWh basis relative to the forecasted amounts. This reconciliation ensures the timely recovery of fuel and purchased power costs for HELCO. HELCO ST-23 at 10.

Dr. Makholm found that HELCO's ECAC compares well to the FACs that are used in traditionally-regulated jurisdictions in the U.S. Nearly all traditionally regulated and most restructured states have some similar mechanism for power cost recovery with complete fuel cost recovery. Like the ECAC, most (about 22) of the 30 traditionally regulated states with fuel clauses have some form of true-up mechanism to reconcile actual and forecasted cost recovery. Also, about 13 of those same states have rate adjustments on a quarterly or more frequent basis. HELCO ST-23 at 11.

3. HELCO's ECAC Complies with Act 162

Act 162 incorporates five requirements for the design of any public utility automatic rate adjustment. Act 162 requires that any automatic rate adjustment be designed to:

(1) Fairly share the risk of fuel cost changes between the public utility and its customers;

(2) Provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy;

(3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts;

(4) Preserve, to the extent reasonably possible, the public utility's financial

integrity; and

(5) Minimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

HELCO ST-23 at 11-12.

a. Fair Risk Sharing of Fuel Cost Changes Between the Public Utility and its Customers

Dr. Makholm stated that the risk of fuel cost changes is comprised of (1) changes in the price of fuel as a single productive input, and, (2) changes in the cost to deliver and produce electricity from HELCO's fuel inputs. This reflects any changes in the technical ability of the utility to turn purchased fuel into electricity, which may require HELCO to purchase a greater quantity of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity. HELCO ST-23 at 12.

Fair risk sharing occurs when the utility has the means to control a cost and it has a corresponding incentive to do so (i.e., it shares the risk associated with that cost). It is not economically efficient to impose risk of cost recovery on the utility when the utility is not able to control the cost. This distinction is critical because the price of fuel is, realistically, beyond the control of the utility. HELCO acts as a price taker in the world-wide market for fuel (oil) and the design of the ECAC and the recovery of fuel and purchased power costs should recognize this fact. HELCO ST-23 at 12.

Under the ECAC, exogenous changes in fuel input costs are passed fully onto consumers. In fuel markets (as in other markets where HELCO is a price taker – service vehicles, for example), it is straightforward to demonstrate prudent purchasing. There is a well-defined market price and a well-defined need to buy from this market (i.e., ratepayers' demand for electricity). In a price-taking market, imposing price change risks on the utility would lead to no efficiency gains resulting from management incentives to minimize costs. This supports the utility's ability to maintain its financial viability, and would increase regulatory lag—the time between rate cases—for costs that are within the utility's control, which would enhance the utility's incentive to control its base rate costs. HELCO ST-23 at 13.

Dr. Makholm stated that the ECAC, with its "heat rate" efficiency factor, provides a partial pass-through of fuel costs. It shares the risks and/or benefits of increased plant operating efficiency by tying HELCO's ability to recover its fuel costs (and thus its financial performance) to its power plant performance over which it has some managerial control, while also allowing HELCO to pass through the exogenous changes in the price of an input over which it has no control, the price of fuel and purchased power. HELCO ST-23 at 13.

HELCO has considerable control over the operation of its plants—limited by engineering realities—and therefore it is reasonable, as the Commission already does, to provide HELCO with an incentive to improve its operating efficiency to manage or lower its fuel costs. The heat rate efficiency factor properly assigns the risk of changes in the cost to deliver and produce electricity from HELCO's fuel inputs to HELCO's management, while allowing changes in the price of fuel to be passed through to ratepayers. HELCO ST-23 at 13-14.

Dr. Makholm stated that plant performance and heat rate targets are used in other jurisdictions. State commissions in Florida, Louisiana, and North Carolina are examples of jurisdictions that have established specific incentives for power plant performance. HELCO ST-23 at 14.

As Dr. Makholm noted, the potential costs associated with improperly assigning power cost recovery risk to the utility could harm the utility's financial health, its credit rating and its ability to raise capital from the financial markets. Accordingly, if a utility only partially recovers its power costs through its FAC, investors will require a higher return on their capital to reflect the riskier investment. While a partial pass-through of power costs may initially reduce the level of rates when unexpected fuel price increases occur, it will ultimately lead to higher costs to consumers. HELCO ST-23 at 14-15.

In addition, the design of the current ECAC mechanism "fairly share the risk of fuel cost changes between the public utility and its customers". Fuel cost changes include fuel price changes and fuel efficiency changes. Under the existing ECAC, customers generally bear the risk of fuel price changes and shareholders generally bear the risk of fuel efficiency changes. Customers pay less when actual fuel prices decline, and customers pay more when actual fuel prices escalate. In establishing a fair rate of return on equity, the Company's current ECAC is assumed to continue (see Dr. Morin's discussion in HELCO T-17). The concept that shareholders do not make any profit from fuel price changes is therefore embedded in the return on equity recommendation. HELCO ST-18 at 5.

It is "fair" that customers bear nearly all the risks and shareholders take minimal risks associated with fuel price changes because the required rate of return on common equity is relatively lower due to the fact that shareholders take minimal risks associated with fuel price changes. As a result, customers benefit by having lower electric rates that are based on the relatively lower rate of return on common equity. HELCO ST-18 at 5-6.

<u>Partial Pass-Through Mechanisms</u>

Some commissions in other jurisdictions have adopted partial pass-through mechanisms. (These are some times referred to as "risk sharing" mechanisms, but that characterization is incorrect given that a utility is a price taker, and would not be able to control the price of fuel and purchased power acquired from the market.) Table 1 in HELCO ST-23 (page 26) provided a brief overview of these mechanisms.

Dr. Makholm stated that these jurisdictions blur the distinction between risk sharing for productive purposes and risk sharing in the price-taking purchase of inputs. In other words, some jurisdictions impose risk sharing on the price of fuel and purchased power. However, these cases are idiosyncratic and have generally been a phase in a broad movement toward less risk imposed on the utilities involved in fuel and power purchases and full pass through of costs.[62] In all cases where a partial pass-through mechanism is used, the fuel and purchased power costs that are not allowed recovery in the FAC are apportioned to the utility for the FAC mechanism only—the companies can file rate cases to recover these increased costs (although with the expense and uncertainty of rate cases). HELCO ST-23 at 27.

The fuel mix and thus exposure (and risk) to oil market price risk of the utilities in these jurisdictions are also dramatically different than HELCO, which relies heavily upon oil for its generation needs. Their large hydro, nuclear and coal resources mitigate much of their exposure

[62] In Arizona, FACs were suspended in 1989, but APS established a new one in a settlement to the 2003 rate case. Thus, APS went from zero percent pass-through to 90 percent pass-through of fuel and purchased power costs.

In Colorado, Public Service Company of Colorado ("PSCO") has other adjustment clauses for DSM costs, air quality improvement costs and purchased capacity that may compensate the utility for the increased fuel and purchased power risks. In its current rate case, PSCO extended its use of its FAC, but was also granted two associated incentive mechanisms: 1) if PSCO achieves coal production greater than a benchmark target, the associated savings would be shared 80/20 with customers, and 2) PSCO would share 80 percent of savings (above a deadband) related to the purchase of economic short term energy.

In Idaho, Idaho Power absorbed all fuel cost changes prior to 1993, 40 percent from 1993 to 1995, and only 10 percent thereafter. Still, major fuel and purchased power cost deferrals (for later collection after contentious base rate proceedings) occurred during the 2000-01 Western Power Crisis. Washington follows similar lines. Neither utility had an FAC and power costs were recoverable through base rate cases. Recent variations in hydroelectric generation supply (due to a seven year drought) increased the size of deferrals and threatened the utilities' finances. Avista filed a petition on January 30, 2006, proposing to eliminate the $18 million deadband of their Energy Recovery Mechanism ("ERM"). In a settlement, Avista's deadband was narrowed to $8 million ($4 million above and below the base level) with a 50/50 sharing of power costs between $4 million and $10 million and a 90/10 sharing of power costs starting at $10 million above or below the base level. The settlement also called on Avista to examine the cost of capital impact of the ERM, as well as the company's hedging strategy for fuel and wholesale power purchases. This represents another movement towards full pass through of power costs. HELCO ST-23 at 27-28.

to the volatile oil and natural gas markets. HELCO ST-23 at 28.

Partial pass-through mechanisms are rare and have been adopted for utilities with no existing FAC in place and should not be considered as a viable option for the sharing of fuel and purchased power costs in Hawaii. HELCO ST-23 at 29-30.

b. Sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy

The second condition required by Act 162 is that automatic rate adjustment mechanisms be designed to "[p]rovide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy."

The second condition is closely tied to the first one. HELCO's targeted efficiency factor promotes productive fuel use decisions and gives HELCO an incentive to reasonably manage or lower its fuel costs. HELCO ST-23 at 15.

If HELCO achieves more efficient plant performance than the level of the efficiency factor then it sees a reward. If HELCO fails to meet this target for some reason, then HELCO would not be able to recover the additional purchased fuel expenditures required to produce the kWhs. HELCO ST-23 at 15.

Like many utilities, HELCO creates and follows an Integrated Resource Plan ("IRP"), which determines the extent of renewables used in HELCO's fuel mix. HELCO ST-23 at 16. The IRP process balances cost-minimization with resource diversity and other concerns. Like purchasing fuel oil from the oil markets, purchasing energy from renewables is not without risks. To ensure the efficient use of renewable resources, the ECAC should cover all purchased energy costs, including renewable sources, on an equal footing. Currently, the ECAC is adjusted each month for changes in the energy mix of the sources of fuel and purchased power. Under an equal footing structure, there is no disincentive from a cost recovery standpoint to purchase renewable energy. The encouragement of renewable energy above and beyond a treatment paralleling non-renewables (i.e., direct subsidization) is a matter of public policy and should not be confused with energy cost recovery. HELCO ST-23 at 16.

Dr. Makholm pointed out that a frequently updated and well designed FAC mechanism could support renewable resource development. The ECAC has positive financial implications and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers. Because the utility serves as a counter-party for renewable energy companies, the credit standing of a utility frequently serves as an important determinant of renewable energy projects' ability to raise capital, and thus, improve reliability and resource diversity. Weakening the utility's credit rating through partial power cost recovery could harm renewable resources that rely on utility counter-party credit to support their investments. HELCO ST-23 at 16.

Dr. Makholm also noted that, just as it is proper in the pursuit of economic efficiency for utilities to have incentives to efficiently manage costs over which they have control, economic efficiency is also served if ratepayers have a cost-based price signal. Ratepayers will not choose to consume an efficient level of electricity if they are shielded from the true costs of producing electricity, and a timely FAC therefore has an important role to play in transmitting these price signals. When consumers are aware of, and can respond to, the cost effects of their energy consumption decisions, they may reduce their demand when the price outweighs the benefit of consuming the product.[63]

c. Mitigating the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts;

The third requirement under Act 162 requires "the public utility to mitigate the risk of

[63] HELCO ST-23 at 16 (citing Braulio L Baez, "Customer Bulletin," Florida Public Service Commission, April 2004).

sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts."

Mr. Meehan's testimony, HELCO ST-24, stated that there are no free lunches in risk management. Hedging has real costs to the party that seeks to reduce its exposure to price movements. In some years, ratepayers may benefit from a price hedge as prices rise, but in times when prices do not rise or fall this will not be the case. In the long run, hedging programs can be expected to increase the overall level of costs associated with fuel and purchased power expenses. Accordingly, if there is a mandate for the utility to reduce ratepayers' exposure to the potential rise in fuel costs, these hedging costs should be passed onto ratepayers. HELCO ST-23 at 18.

Act 162 recognizes that there are alternatives "commercially available" to customers that can mitigate price risk for customers. A utility can mitigate the risk of fuel cost changes through two forms of hedges: (1) Physical hedges, such as long-term supply and purchased power contracts and maintaining fuel inventories; and (2) Financial hedges. In HELCO ST-24, Mr. Meehan surveyed the potential financial hedging instruments that are available to HELCO and their potential impacts. Dr. Makholm stated generally, financial hedges either require payment to intermediaries in cash to bear risks or otherwise pay through giving up the prospect for lower future fuel prices. If utility ratepayers are willing to pay for the additional service of hedging their price risk, the ECAC would include these costs. Currently, the ECAC allows the recovery of the unhedged fuel costs, but is unclear regarding whether financial hedging costs would be recovered in the ECAC. HELCO ST-23 at 19.

i. Fuel Hedging

The Edison Electric Institute ("EEI") defines hedging as "the attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks." Hedging can, in principle, allow a utility to offset and reduce risk as it procures fuel and purchased power on behalf of its customers. HELCO ST-24 at 2.

HELCO generates electricity primarily by burning oil. To ensure a reliable physical supply of oil, HELCO has a variety of oil supply contracts that govern the purchase of suitable fuel oil delivered to its plants. These contracts call for HELCO to pay a price each month based on contract formulas. The key factor affecting these formulas is the relevant oil index on a daily basis over the month. The oil index is the reported market price of transactions in a standard oil product at a particular location. For example, the contract for the industrial fuel oil burned by HELCO is tied to the daily index for L.A. Bunker C fuel oil. Mr. Meehan stated that this is a sensible index as it is economic for HELCO's supplier to acquire such oil to meet HELCO's needs and as HELCO's supplier will want to sell at a market price. HELCO ST-24 at 2-3.

Purchasing oil at a formula rate tied to oil products that are traded in the worldwide oil market means that HELCO's fuel costs will vary with world oil prices. It also means that HELCO's fuel supplier is not taking world oil price risk, and can offer HELCO a price free of a world oil price risk premium. Thus, HELCO can offer its customers a price for electricity that is free of any risk premium associated with bearing world oil price risk. HELCO ST-24 at 3.

<u>Background</u>

In regulatory parlance and in many industries, the term "hedging" most often refers to short-term activities (i.e., a year in duration or less). This is because forward markets offer liquid price hedging contracts covering delivery periods that often extend only for one or two years forward. For the oil derivatives markets, price hedging contracts are only reasonably available for periods of up to twelve months. This means that hedging contracts, if pursued by HELCO, could only mitigate the impacts of oil price changes on costs and rates for a defined period such as one quarter or potentially one year. Fuel hedging contracts could not be expected to cover durations longer than this. HELCO ST-24 at 13.

Long-term hedging – i.e., hedging for more than one year in the future – cannot reasonably be achieved through commercially available fuel hedging contracts. Long-term hedging for HELCO would require investment in non-oil based generation capacity, either through rate-based generation or through long-term contracts with non-utility generators. HELCO ST-24 at 13.

Hedging is not necessarily beneficial. It depends on the objective of the entity engaged in the hedging. Hedging is most often done to lock in a range of outcomes and not to maximize expected value. In fact, hedging reduces the expected value of profitability and raises the expected value of power costs. Hedging can be beneficial to a firm that seeks to reduce the range of potential outcomes, but hedging creates costs and risks. HELCO ST-24 at 14.

There are specific circumstances when hedging might be appropriate. There are certain situations where firms face business or financial risks that make hedging particularly important. For example, if prices for the firm's product will remain relatively fixed as a significant input cost varies, then hedging that input cost may be necessary to protect cash flows and maintain financial stability. This will be the case when the firm is more reliant on a specific commodity than the industry in general and changes in that commodity's price do not have a proportional impact on market prices. This could also be the case when industry competitive pressures are so severe that product prices cannot rapidly adjust to meet changes in input costs. HELCO ST-24 at 14.

Hedging differs from speculation. Speculation is defined as taking a position with the intent to profit from a change in the price of the underlying commodity. Hedging differs from speculation in that hedging is intended to insulate profits from the effect of changes in the underlying commodity. Hedging is the polar opposite of speculation. Some activities deemed to be hedging by unregulated firms are actually speculation. This is the case when the firm seeks to profit from a change in the price of the underlying commodity as opposed to holding itself neutral to such a change. HELCO ST-24 at 14-15.

The motivation for regulated utilities to hedge is different from the motivation of firms in competitive industries. Regulated utilities with highly variable fuel costs generally have fuel adjustment clauses in place that provide for timely and adequate recovery of costs. HELCO ST-24 at 15.

Hedging by regulated utilities is oriented toward managing customer rates; its objective is to insulate customers from the price fluctuations in an underlying commodity. For example, some gas and power distribution utilities hedge the commodities they sell in order to provide a fixed- or near-fixed price to customers. It only makes sense to hedge if the intent is to sell at fixed or "near fixed" rates.[64] HELCO ST-24 at 15.

Mr. Meehan stated that his experience has been that hedging programs are designed and implemented by utilities in collaboration with the commissions that regulate them. The utilities agree upon an objective with the regulator and then they clearly establish a program for

[64] By "near fixed rates", Mr. Meehan stated that in his experience it is very unusual for electric utilities to offer rates that do not fluctuate based on changes in fuel and purchased power markets. This can mean rates that fluctuate monthly, which give customers an economically-desirable price signal to reduce usage when power costs go up. However, it can also mean rates that are "near fixed", in that they are set for a period of time and differences are reconciled on a semi-annual or annual basis. In these circumstances, a utility may attempt to minimize differences by hedging with fixed price purchased power contracts or fuel hedges. Mr. Meehan stated that he uses the term "near fixed rates," because even in cases where a utility hedges, the rates are not completely fixed. Utilities are not well positioned to offer fixed rates, and even in instances where they may engage in some hedging, the rates are at most "near fixed" as opposed to fixed because complete (i.e., perfect) hedging is unachievable. HELCO ST-24 at 15.

achieving that objective. The need for a regulated entity to hedge is created by a specific and customer focused objective, not by the economics of the regulated business model. Therefore, it must involve considerable regulatory oversight and guidance. HELCO ST-24 at 16.

Mr. Meehan stated that utilities do not hedge in order to obtain the best or lowest possible price for fuel because that would not be hedging, it would be speculating. Any fuel hedging program with the objective of "timing the market" and "buying low," is not a hedging program. Utilities have no specialized expertise in identifying trends in world oil markets and cannot be expected to predict market high and low points. That job is left to professional traders and speculators. A utility should not be asked to speculate on behalf of its customers. Moreover, a utility should not bear any financial risk or reward related to the timing of hedge execution. Utilities hedge to lock in a current market price and reduce fluctuations and not to minimize fuel acquisition costs. HELCO ST-24 at 16.

Act 162

Act 162 raises the question of whether HELCO should hedge by reference to "fuel hedging contracts" as a commercially available means to mitigate the risk of fuel price changes. Mr. Meehan stated that HELCO could, in theory, hedge fuel by buying financial products called oil price futures. Were HELCO to buy oil price futures, it would realize profits when oil prices rise and losses when oil prices drop. This is a hedge, because the gain or loss is opposite in direction to what HELCO pays for oil under its contracts. HELCO ST-24 at 3.

Hedges are accomplished using financial instruments called derivatives. They are called derivatives, because their value is derived from the market price of an underlying commodity. An oil future, for example, is settled against the price of oil and is an oil derivative. HELCO would buy derivatives and the value of these derivatives would rise when HELCO's actual contract purchase costs rise, and fall when HELCO's actual contract purchase costs fall. Thus, they would offset or hedge actual contract purchase costs. HELCO ST-24 at 4.

There are factors that can prevent hedging from achieving the goal of safe, adequate and reliable service at the lowest reasonable cost. Mr. Meehan identified four factors to consider:

1. Downward price movements may be foregone. Locking in a price for oil today or at some fixed point for delivery in the future does not provide for a lower price, just a known price. The price locked in may well be higher than the price in the future at which HELCO actually purchases oil. Hence, hedging does not provide for lower prices. It only increases predictability, which may not be perceived as beneficial by all customers. HELCO ST-24 at 6.

2. Hedging involves costs. These costs are incremental to the fuel acquisition costs when fuel is not hedged. Customers can expect to pay more if HELCO adopts fuel hedging. It is not at all clear that increased predictability is worth the extra costs. HELCO ST-24 at 6.

3. Hedging is imperfect. Perfect hedges can only be accomplished when the hedged product is identical to the acquired product and when the volume needed by the hedger is certain. HELCO could not buy derivatives that correspond exactly to the product that will be acquired. It would need to hedge using similar, but not identical, products. This would pose what is called basis risk.[65] In HELCO's case, basis risk is substantial because the indexes in HELCO's oil contracts are not traded in the most liquid and transparent derivatives markets and because the closest substitutes are only traded in less liquid and less transparent derivative markets. When a regulated utility

[65] Basis risk is the difference in price movement between the derivative used to hedge and the price movement in the product that will actually be bought.

hedges, it is best done in transparent liquid markets. The products available in the transparent and liquid oil derivative markets, however, do not move in lock step with the indexes in HELCO's contracts. Further, HELCO pays for oil based on average daily prices in the indexes. If HELCO were to hedge, it would settle once a month and this itself would create a basis difference between the derivative used and HELCO's actual costs. This basis difference means that if HELCO were to attempt to hedge, it could only partially do so, and its hedges would not be fully effective. Mr. Meehan looked at several years of historic data and found that this is not just an academic issue, and HELCO would have a difficult time placing effective hedges. HELCO ST-24 at 4-5.

4. Limited duration of financial hedges. HELCO could hedge oil prices at most for a year out in the future. Hence, while there may be an enhanced degree of price predictability, it would be for a limited time and would not protect customers against long term trends in oil prices. HELCO ST-24 at 5-6.

Mr. Meehan's Conclusions

Mr. Meehan presented the following conclusions with respect to fuel price hedging.

1. Even if rate smoothing is a desired goal, there may be more effective means of meeting the goal.[66] There is no compelling reason for HELCO to use fuel price hedging as the means to achieving the objective of increased rate stability. The basis for his first conclusion is rooted in the fact that hedging carries a limited scope of benefits, and also implies costs and risks for customers. The scope of benefits from hedging is limited by the realities of the oil hedging marketplace and HELCO's physical location. HELCO ST-24 at 6-7.

[66] HELCO may be able to achieve increased short-term rate stability more effectively through the ratemaking process. Dr. Makholm discussed these alternatives in HELCO ST-23.

First, the duration of any benefit is limited: the markets do not offer reasonable hedging solutions that would permit HELCO to manage oil price-driven rate fluctuations for more than one year at a time. Second, there is no ex ante expected price benefit. Even if hedging can stabilize purchased oil prices to some degree, the stabilized price may be higher or lower than the price that would have been achieved absent the hedging program. On average, costs can be expected to be higher with a hedging program. Third, the amount of fuel cost stability that can be achieved is uncertain due to basis risks, quantity risks and other risks. HELCO cannot enter into readily-traded fuel hedging contracts that eliminate all exposure to oil price fluctuations; such contracts do not exist in the marketplace. The risks inherent in available fuel hedging contracts create uncertainties as to how effective hedging products would be in stabilizing prices for customers. The cost of bearing these risks is potentially high. HELCO ST-24 at 7-8.

2. While HELCO could partially hedge against oil price risk for periods of just over a year into the future, there would be considerable costs to doing so. The liquidity of standard financial hedging products with a term of over a year is limited. Given this, price hedging should not be expected to address rate periods of more than one year at a time. HELCO ST-24 at 6.

This second conclusion is based primarily on Mr. Meehan's analysis of the oil hedging market. He examined the types of price-risk management contracts that are available through the over-the-counter ("OTC") market and exchange markets. Mr. Meehan found that the contracts that are most actively traded are the contracts for very near term deliveries (i.e., delivery within the next three to six months). In addition, Mr. Meehan found some trading of contracts for deliveries covering six to eighteen months in the future. For deliveries in periods beyond eighteen months in the future, trading is very thin or non-existent. HELCO ST-24 at 8.

The most liquid exchange-traded contracts that would be available to hedge the fuel needs of HELCO are the New York Mercantile Exchange ("NYMEX") heating oil futures contract based on pricing at New York Harbor and the NYMEX West-Texas Intermediate crude oil futures priced at Cushing, Oklahoma. HELCO-S-2401 illustrates how trading drops off for longer-dated delivery periods for these contracts.[67] HELCO ST-24 at 8-9.

3. Were HELCO to hedge, it would at best be able to partially hedge as there are considerable differences in price fluctuations between the hedges HELCO could readily purchase and the cost of the oil it burns. Further, the Company would not know with certainty the exact volume of oil it needs. Moreover, prices should signal costs. While some customers may desire rate stability and predictability, and be willing to pay, others may not be willing to pay for predictability. One way to deal with this issue would be to allow customers to "opt in" to rate stability programs, such as hedging initiatives that may be expected to raise average overall costs to customers. HELCO ST-24 at 6.

Based on his review of HELCO's existing physical fuel contracts and his review of available price hedging products in the marketplace, Mr. Meehan found that HELCO would not be able to eliminate all of the risk of oil price fluctuations. The fuel contracts contain complex pricing provisions that are based in part on published fuel assessments, but also contain adjustments for product quality and in some cases freight costs. This means that even if HELCO were able to hedge the published assessment, the final cost of delivered oil would remain subject to residual price risks that could not be hedged. HELCO ST-24 at 9.

Further, Mr. Meehan's review of the over-the-counter oil derivatives markets turned up

[67] HELCO-S-2401 illustrates how liquidity is concentrated in the near-term delivery months. Hedging with contracts that are thinly traded poses risks and tends to be more expensive. Mr. Meehan stated that given the trading activity for these futures markets, it would not be reasonable to expect HELCO to hedge beyond 12 months into the future. It is important to recognize that there are higher liquidity risks associated with the longer-dated contracts, and there would be liquidity risks and illiquidity premiums even within the twelve-month time horizon. HELCO ST-24 at 9.

no visible contracts for the specific fuels that are referenced in HELCO's fuel supply contracts. This means that HELCO would have to bear the basis risks or pay a premium to shift those risks to a third-party via a customized swap, which may be expected to increase average costs for customers. HELCO ST-24 at 9-10.

Moreover, the fuel hedging contracts that are available in the marketplace are for fixed quantities. HELCO's customers would therefore bear market risk exposure for incremental or decremental quantities relative to the fixed quantity that is hedged by HELCO. HELCO ST-24 at 10.

All of these factors imply that even with a short-term price hedging program, there would still be fluctuations – potentially large fluctuations – in HELCO's cost of fuel. HELCO ST-24 at 10.

4. Were HELCO to hedge, it would encounter periods during which it experienced gains on its hedges and other periods during which it experienced losses. The gains in large part would be offset by increased fuel purchase costs and the losses in large part would be offset by reduced fuel purchase costs. The ECAC framework would need to be revised so that the difference between the gains and increased fuel costs and the difference between the losses and reduced fuel costs were reflected in rates through the ECAC. HELCO ST-24 at 6-7.

Gains and losses are a natural part of hedging. Through its price hedging activities, HELCO would effectively be using forward contracts to lock in a price for oil for delivery periods in the future. If prices for those delivery periods rise subsequent to HELCO's having locked in its price, HELCO will experience a gain on its hedge. If prices fall subsequent to placing its hedge, HELCO will experience a loss. The mechanics of financial settlement of the hedges are such that any differential between the forward price locked in and the price at maturity would be multiplied by the fixed quantity that HELCO had hedged to arrive at a settlement cost for the contract. The hedging contracts will create gains and losses, but as noted, those gains and losses will be partially offset by changes in the cost of delivered oil. HELCO ST-24 at 10.

The net result is that HELCO would continue to experience variable net fuel and hedge costs even with a hedging program. In HELCO ST-23, Dr. Makholm elaborated on the reasons why it is important to flow through the net fuel costs (i.e., fuel costs adjusted for hedge gains and losses) in an ECAC. HELCO ST-24 at 10-11.

Further, if hedging is pursued, it will be important for HELCO and the Commission to agree on the objective of hedging, an acceptable hedging program, including the specification of approved contract types and contract duration, an approved timescale for hedge execution, as well as the revisions to the ECAC cost recovery framework. HELCO ST-24 at 11.

5. Hedging of oil by HELCO would not be expected to reduce fuel and purchased power costs and, in fact, would be expected to increase the level of such costs. HELCO ST-24 at 7.

Utilities are not in the business of predicting world oil prices and cannot be expected to consistently buy low. If fuel hedging contracts are entered into by HELCO, there will be no way to know on an ex ante basis whether market prices will move up and those hedges will lower rates for customers or whether market prices will move down and those hedges will raise rates for customers. There are certain explicit costs to hedging, and if pursued, HELCO would face new risks that it does not currently face. See HELCO-S-2402. These risks and costs lead to fuel costs from hedging that can be expected on average to be higher. The trade-off is an expected increase in rate stability at the cost of higher expected costs, as recognized by the National

Regulatory Research Institute ("NRRI")[68]:

> Hedging, in its purest form, does not provide a means to reduce the expected price of gas for a utility. Rather, from the consumers' perspective its primary function is to stabilize prices. Generally, risk-adverse consumers should be expected to pay extra for shouldering less risk, such as exposure to volatile prices.

HELCO ST-24 at 11.

6. It would not be reasonable for HELCO to take the position of a principal and speculate in the oil market with shareholders assuming the risk of oil derivative gains and losses. HELCO ST-24 at 7.

Mr. Meehan stated that the motivation for hedging would be to provide rate stability for customers. HELCO would thus be entering into hedges on behalf of customers, not on its own behalf. It is logical that customers bear the risks and rewards of hedging. Under the regulatory compact, shareholders bear certain risks and reap certain rewards. However, gains or losses on hedges that were entered into on behalf of customers under the direction of the Commission should not be shareholder responsibility. (Dr. Makholm explained in HELCO ST-23 why having the utility share in the risk of input costs when the utility is purchasing in world markets and is a price-taker is contrary to sound regulatory practice and would violate the regulatory compact.) HELCO ST-24 at 12.

<u>Mr. Meehan's Recommendation Concerning Fuel Hedging</u>

Mr. Meehan recommended that any exploration into hedging by HELCO recognize the following:

1. There is no business reason for HELCO to hedge and the benefits to customers are unclear;

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[68] HELCO ST-24 at 11 (citing Ken Costello, "Regulatory Questions on Hedging: the Case of Natural Gas," National Regulatory Research Institute, February 2002, p. 17. Reprinted in *Electricity Journal*, May 2002, p. 51).

2. Fuel (oil) hedging by HELCO will be expected to result in increased customer costs and as such should only be seriously considered if there is a countervailing benefit;

3. Fuel hedging by HELCO may be able to reduce oil price-induced fluctuations in customer rates, but would not eliminate such fluctuations. While rate stability may be a countervailing benefit to the costs of hedging, hedging will provide, at best, more and not absolute rate stability;

4. If fuel hedging were to be implemented, fuel hedging objectives would need to be developed in close consultation with regulators and customers and approved a priori as hedging by HELCO on behalf of customers and not for HELCO's shareholders account; and,

5. If HELCO were to implement fuel hedging it should not speculate by attempting to time the market to minimize oil purchase costs. HELCO ST-24 at 17,

Further, Mr. Meehan recommends that HELCO carefully consider limitations on its ability to hedge that are a function of marketplace realities and the implications of hedging on its financial position. HELCO ST-24 at 17.

HELCO's Current Situation

To meet the electricity demands of its customers, HELCO operates oil-fired power plants. HELCO purchases the oil for these plants. HELCO's position in oil is therefore a short physical position. HELCO hedges its short physical position by entering into an offsetting long position in delivered oil. This long position is achieved through the Company's existing fuel supply contracts. These fuel supply contracts tie the price paid by HELCO for oil to a base component. The base component is the month-to-date average of a third-party assessment calculated on the 20th of the month before delivery. The actual contract price includes taxes and a standard premium (based on quantity). Depending on the contract, the price may include a locational premium and adjustments for heat content, quality differentials and freight. In addition, the contracts provide for quantities and delivery of fuel that are more than sufficient to cover HELCO's needs. Hence, HELCO and HELCO's customers are hedged with respect to availability and delivery of the physical commodities. HELCO's fuel costs are variable as the price it pays will vary with the daily assessments in HELCO's fuel contracts. HELCO ST-24 at 17-18.

With respect to price, despite the fact that the price varies with assessment values, HELCO is hedged from the perspective of the utility. HELCO's physical fuel supply contracts are struck at floating assessments. Similarly, its electricity rates float in accordance with the prices of oil that HELCO pays. The matching of variable fuel operating expenses with variable electricity revenues helps to assure the financial integrity of the utility, while providing the economically-correct price signal to customers. HELCO ST-24 at 18.

The fuel hedging contracts referred to by Act 162, if reasonably available, would only be entered into by HELCO to meet the objective of mitigating oil price fluctuations for customers. Customers are exposed to fluctuations in world oil prices, while hedged against availability and physical delivery risks and costs. If HELCO were to hedge price risk, it would reduce this price exposure. Of course, there would be a cost to reducing the exposure that may not be justified by the benefit. HELCO ST-24 at 18.

Different Hedging Strategies

Mr. Meehan stated that buyers of commodities can use a number of different hedging strategies to manage short-term price risk. Mr. Meehan discussed the three strategies that are commonly used by buyers of commodities.

1. Forward or futures contracts.[69]

Forward contracts are in most cases struck at fixed prices.[70] A fixed-price forward contract locks in the price of the underlying commodity for both the buyer and seller. (HELCO-S-2403 illustrates the effect of a forward contract purchase for a buyer who, like HELCO, would otherwise be purchasing the commodity on the open market at prevailing spot prices.) HELCO ST-24 at 19-20.

HELCO-S-2403 provided an example where HELCO fully hedges its fuel need with futures contracts at $40/bbl. No matter what happens to the price of oil from this point on, HELCO will pay $40/bbl for oil. However, even though the initial hedge may have been perfectly rational ex ante, subsequent decreases in the price of oil will increase costs relative to a no-hedging strategy and increases in the price of oil will decrease costs relative to a no-hedging strategy. This exhibit illustrates the impacts that purchasing forward can have on the price paid, but does not consider basis risks. HELCO ST-24 at 20.

Basis risks are the price risks that a buyer would be exposed to if the buyer cannot find a forward contract for the specific commodity it needs at the delivery location it needs. If the marketplace does not offer forward contracts that exactly match the commodity and the location where the buyer takes delivery, the buyer may purchase derivatives for a different commodity whose price is highly correlated with the product the buyer wishes to hedge. In addition, the buyer could purchase the same commodity it needs but at a delivery location other than the one where it takes delivery. In these cases, the buyer faces the risk associated with the difference in

[69] A forward contract is an agreement between two parties to buy or sell an asset or commodity at a pre-agreed future point in time. A standardized forward contract that is traded on an exchange is called a futures contract. HELCO ST-24 at 19.

[70] A fixed-for-floating swap is a contract between two parties under which one party agrees to swap a fixed price for a published index price on a notional quantity. A fixed-for-floating swap is economically equivalent to a fixed-price forward contract. The difference is that the fixed-for-floating swap is a purely financial instrument, while a forward contract generally anticipates physical delivery. HELCO ST-24 at 21.

prices between the two commodities or the two locations. These price differences are termed basis risk. HELCO ST-24 at 20.

Even firms engaged in sophisticated hedging programs, such as Southwest Airlines, have run into problems with respect to basis risk. Mr. Meehan stated that, while he is not an accountant, it was his understanding that Statement of Financial Accounting Standards No. 133 (FASB 133) has strict provisions regarding basis risk, requiring that ineffective portions of hedges do not qualify for special hedge accounting treatment. Southwest Airlines' hedging program aims to hedge the price of jet fuel, an underlying commodity that is not traded on an organized futures exchange. Southwest Airlines explains that "ineffective" hedges are inherent to "hedging jet fuel with derivative positions based in other crude oil related commodities" and goes on to explain that ineffectiveness "may result, and has resulted, in increased volatility in the Company's results." Thus, it is clear that basis risk is a significant issue, and may, in fact, preempt HELCO from pursuing a financial hedging program that involves "ineffective" hedges. Customers may not be well served by hedges that involve basis risk. HELCO ST-24 at 20.

2. Call option contracts.[71]

HELCO-S-2404 shows the payouts that HELCO would incur/receive by fully hedging its fuel needs with a call option with a strike price of $70/bbl. This strategy would cap the cost of oil at $70/bbl + the cost of the option (in $/bbl). If the strike price at the time of delivery proves to be less than $70/bbl, the call will produce no financial benefit and the cost of the strategy will be the cost of oil plus the cost of the option. If the price of oil proves to be above $70/bbl, revenues from the call option will completely compensate for any increases in the price HELCO

[71] A call option gives its owner the right, but not the obligation, to buy an asset or commodity on a specified date (the expiration date), for a specified price (the strike price). (HELCO-S-2404 illustrates the payouts that would accrue to the purchaser of a call option. Call options cap the price that will be paid by a buyer for a commodity.) HELCO ST-24 at 21-22.

pays for oil. Again, this exhibit does not capture basis risks. HELCO ST-24 at 22.

3. Collars (which are portfolios containing call option contracts and put option contracts).[72]

HELCO-S-2405 illustrates a collar using a call option with a strike price of $70/bbl and a put option with a strike price of $50/bbl. If the price of oil proves to be above $70/bbl, revenues from the call option will completely compensate for any increases in the price HELCO pays for oil. If the price of oil proves to be below $50/bbl, payments made to settle the put option will completely compensate for any decreases in the price HELCO pays for oil. Thus, HELCO's fuel costs will be between $50/bbl and $70/bbl. HELCO ST-24 at 22-23.

Marketplace Realities

Mr. Meehan identified a number of practical obstacles or constraints that HELCO would face if it were to enter the marketplace seeking to hedge on behalf of customers, that is, if it were seeking to limit the impact of fluctuations in world oil prices on customer rates.

1. The first constraint relates to the duration of the hedge. The liquid forward and futures contracts that are traded in the marketplace do not extend beyond a term of 18 months. Further, the most liquid (i.e., readily-available to trade) fuel hedging contracts are contracts that cover time periods of up to six months into the future. (This is illustrated in HELCO-S-2401.) HELCO ST-24 at 23.

2. Hedging contracts for the precise oil products and delivery points that HELCO would need are not visible in the marketplace. HELCO would therefore be exposed to considerable

[72] A collar is a portfolio of options that are used to assure that the price of a commodity is within a given range. A buyer of a commodity who wishes to put a cap and floor on the price paid would sell a put option and buy a call option. This strategy assures that the price of the commodity will be within a given range – i.e., no lower than the strike price of the put (the floor) and no higher than the strike price of the call (the cap). (HELCO-S-2405 shows the payouts that would accrue to the purchaser of a collar ignoring basis risks.) HELCO ST-24 at 22. A put option gives the owner the right, but not the obligation, to sell a commodity at specified price. Thus, a seller can use a put to determine a minimum price he will obtain on his sale.

basis risks if it used the oil derivatives that are readily-available in the marketplace. It is possible that HELCO could obtain a customized swap agreement that hedges the price of the specific oil products in the specific locations that form the basis for the pricing formulas in HELCO's physical oil contracts. However, such a swap would be less transparent and it can be expected to be more expensive because the seller of such a swap would need to be remunerated for absorbing the basis risks and illiquidity of offering such a hedge. HELCO ST-24 at 23-24; HELCO ST-2406 (illustrating the potential size of basis risks).

In addition, there is an issue of the incongruence of pricing dates relevant to the hedging commodity and the short commodity. Whereas HELCO's contracts for fuel are based on lagged thirty-day average prices, cash flows from hedging would be based on two days, the day on which the hedge is purchased and the settlement date (the last trading day before delivery). Thus, while the settlement date of a hedge will reflect price movements up to the day before delivery, the price of the short commodity will reflect markets 10 to 40 days earlier. Changes in the market during the forty-day period before the settlement date will affect the basis and cause the hedge to be less effective. See HELCO ST-24 at 24-25; HELCO-S-2407 (illustrating the magnitude of these basis changes).

If HELCO were to look for alternatives, it would most likely be limited to customized products in the over-the-counter market. However, as mentioned above, prices for such products would most likely be less transparent and more expensive, which would increase costs and risks for customers. HELCO ST-24 at 25.

3. The third constraint faced by HELCO is the quantity which it would hedge. The quantities that HELCO needs of each type of fuel fluctuate month to month and year to year in accordance with changing demand, availability and relative economics of generation plants,

among other factors. HELCO's smaller size, relative to HECO, increases the significance of this constraint. HELCO's existing fuel contracts provide for flexibility on the quantities taken, subject to a minimum and maximum take. The quantity flexibility embedded in HELCO's existing fuel contracts would be difficult to match in the financial derivatives markets, which offer fixed quantity products. This quantity risk is important and makes hedging difficult. HELCO ST-24 at 25; HELCO-S-2408 (illustrating the variable quantities needed for each type of oil used by HELCO).

4. If HELCO decides to engage in hedging, HELCO may face credit risk. Credit risk is the risk of a financial loss associated with the failure of a party to perform on its obligations under a hedging contract. Credit risk is an important factor when considering fuel hedging contracts. Market practice is to mark forward contracts to market and to collateralize the credit exposure embedded in forward contracts. This means that the value of the contract is calculated every day and any exposure must be covered as margin. If HELCO engages in hedging, counterparties may require that HELCO provide collateral. The provision of collateral would add to the cost of hedging. Further, HELCO would in most instances be exposed to the risk of counterparty default and non-performance. HELCO ST-24 at 25-26.

5. The execution of fuel hedging contracts would expose HELCO to liquidity risks. Liquidity is the ability to execute transactions in the marketplace. Markets that are highly liquid have active trading and many buyers and sellers. Market liquidity for oil derivatives ebbs and flows. When the markets are less liquid, buyers and sellers may face difficulties entering into or exiting positions. Markets with low liquidity may inhibit HELCO's ability to execute or unwind hedge positions. In addition, low liquidity would harm HELCO's ability to replace a position as a result of counterparty default. Low liquidity also impedes the ability of a buyer to obtain a

favorable price. The risk that these markets would not be liquid is a real one and could present significant price penalties and transaction constraints. Liquidity and its effect on price and the ease of making transactions should be fully understood and examined prior to HELCO's embarking on a hedging program. HELCO ST-24 at 26.

6. The contract sizes for the hedging instruments HELCO could use have minimum contract sizes of 1,000 bbls (42,000 gallons).[73] If HELCO were to pursue a hedging strategy separately from its affiliates, its ability to effectively develop a portfolio of hedging instruments may be limited to an extent by the minimum contract size. HELCO ST-24 at 26-27.

Mr. Meehan prepared a summary of the costs and risks for HELCO and its customers of entering into fuel hedging contracts in HELCO-S-2402. An analysis of whether the hedging alternatives that are available in the exchange and OTC markets are reasonable for HELCO to enter into must consider the risks shown in that exhibit. These factors indicate the fact that HELCO's fuel costs will continue to fluctuate even if hedges are entered into due to risks that cannot be hedged. They also indicate that hedging will introduce new costs for customers that are not borne under the current regulatory regime. HELCO ST-24 at 27.

Were HELCO to hedge using the most liquid products, it would face considerable basis risks. That is, the liquid, transparent and readily available hedges pose basis risk and would have limited hedge effectiveness. Again, basis risk arises from the change in prices of the hedge differing from the change in price of the actual physical commodity that HELCO purchases. Were HELCO to hedge using products with less basis risk, these products would be less liquid and less transparent. This is especially problematic for a regulated firm that must be able to

[73] Thus, a single contract may represent a significant percentage of HELCO's fuel obligation for a particular month. For example, in January 2005, HELCO took delivery of 17,700 bbls of diesel, less than in any other month that year. A 1,000 bbl heating oil contract corresponds to about 5.6 percent of this potential hedge.

demonstrate the reasonableness of its purchases. Neither buying less effective hedges nor buying less liquid and less transparent hedges is desirable as there are more effective means of achieving the same objective. HELCO ST-24 at 27-28.

ii. Alternatives Other Than Hedging Price Risk

Dr. Makholm identified alternatives available other than hedging price risk changes that can provide similar rate smoothing benefits to price risk hedging, such as budget billing plans and fixed rate plans. HELCO ST-23 at 19.

Budget billing is an optional payment program that allows the customer to pay the same amount each month for electricity or natural gas usage throughout the entire year. The voluntary nature of these programs limits any negative consumer feedback and targets the program to the consumers that want it. A monthly bill based upon previous usage patterns is estimated for the upcoming year. At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan. Budget billing is typically offered to residential and small commercial customers as part of a plan to manage volatile changes in monthly energy costs. It should be noted that budget billing does nothing to mitigate rising electricity costs. Participants still pay the full amount for electricity, only the timing of payments over the course of the year is adjusted. Most states currently have a form of budget billing program available to residential customers. The need for a budget billing plan in Hawaii may not be as large as most continental U.S. states due to the relative lack of seasonality in demand. HELCO ST-23 at 19-20.

Some states have allowed utilities to have a rate option called "fixed rate" or "flat bill" in which a customer pays a flat bill with no reconciliation, but with a risk premium. Fixed rate billing programs are generally available for larger commercial and industrial users who value (and are willing to pay for) insulation from unexpected price increases. HELCO ST-23 at 20.

The risk premium is necessary because fixed rate billing does present risks and additional costs to the utility. If fuel and purchased power prices are higher than expected, fixed rate billing will under-collect. The opposite is also true. Therefore, customers electing a fixed rate billing option may force the utility to hedge against a position in the market for the underlying oil commodity. If a utility offering a fixed rate or flat bill program did not hedge against this fixed price obligation, the utility would be effectively speculating on the fuel markets. (As discussed above, there is an inability to hedge HELCO's fuel price exposure fully.) Thus, any expected costs that may result from a fixed rate billing program would increase the flat bill rate over the regular tariff structure. The risk premium should be large enough to compensate the utility for any added risks and costs on average, but during periods of rising fuel prices, a large group of ratepayers taking out a fixed rate may affect a utility's liquidity and its financial health. HELCO ST-23 at 20.

Fixed rate billing may provide benefits to larger customers similar to budget billing (rate stability) with the added benefit of insulation from input cost increases. Rates will, on average, be higher for the customers who select this option. HELCO ST-23 at 20.

Dr. Makholm stated that if there is a demand from customers and/or a mandate from the Commission acting on behalf of ratepayers, then recovery of the hedging and risk premium costs associated with physical and financial hedges should be included in the ECAC. However, there are other alternatives available, such as budget billing and fixed rate billing, that may provide the benefits sought through hedging programs (rate stability), and which would not require pursuing these potentially costly options. HELCO ST-23 at 21.

With respect to implementing budget billing, HELCO stated that it will explore an optional revenue neutral budget billing rate schedule for residential and Schedule G customers. In addition, HELCO will submit to the Commission, within 12 months from the date of the Commission's final decision and order ("D&O") in this docket, a pilot budget billing program for its review. HELCO cannot currently implement budget billing using its existing customer information system ("CIS"). The new CIS, however, will be able to handle budget billing, but is not expected to be in-service until the first half of 2008. Therefore, while HELCO may submit its pilot budget billing program and tariff for Commission review within 12 months of the Commission's final D&O in this docket, the schedule for actual implementation of the pilot depends on the in-service date for the new CIS. HELCO RT-22 at 7.

d. Preserving, to the extent reasonably possible, the public utility's financial integrity

The fourth requirement of Act 162 is to "[p]reserve, to the extent reasonably possible, the public utility's financial integrity." A FAC generally, and HELCO's ECAC specifically, preserves the financial integrity of a utility and HELCO in particular. Dr. Makholm stated that for modern utilities that operate in a world of volatile fuel prices, a FAC is critical to:

(1) Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with the most difficulty in tracking input costs.

(2) Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.

(3) Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating. Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely scrutinize cost-recovery mechanisms. Credit rating agencies, for example, recognize the

need for robust and frequently updated FAC mechanisms.[74] HELCO ST-23 at 21-22. S&P has often cited the existing ECAC mechanism as a strength in HECO's credit quality assessment. Conversely, the potential to change the existing ECAC has raised concerns with the rating agencies as noted in S&P's credit assessment of HECO dated November 22, 2006 in Exhibit HELCO-ST-1801. HELCO ST-18 at 6-7.

(4) Maintain HELCO's ability to raise capital. Because oil and other fuel expenses are a large portion of HELCO's operational costs, the ECAC is necessary because it allows HELCO to raise capital at a reasonable cost in good markets and bad. HELCO ST-23 at 22.

Utility regulators have long recognized the crucial role that cost-recovery mechanisms play in allowing the utility an opportunity to recover its costs. FACs permit a utility to recover its costs and assure the capital markets that the company can meet its obligations to shareholders and bondholders.[75] HELCO ST-23 at 22.

Continuation of the ECAC would allow HELCO to more readily raise capital in the future, which will improve HELCO's ability to meet future infrastructure needs and preserve the level of service demanded by its ratepayers and the Commission. The Company recognizes this fact as the most recent 10-K states that:

Risks, uncertainties and other important factors that could cause actual

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[74] HELCO-S-2301 presents a selection of statements from the three major credit rating agencies detailing the critical role of power cost recovery in their credit rating evaluation process.

[75] Colorado provides an example of a state commission balancing the concerns of the utility and its customers. The Colorado commission explained its long-term use of FAC mechanisms by stating that it established its FAC in order to permit rapid recovery of increased costs over which the utility has no control. The Colorado commission recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing the utility's ability to provide service. HELCO ST-23 at 22.

When approving the Arizona Public Service Company's ("APS") proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates." HELCO ST-23 at 22.

> results to differ materially from those in forward-looking statements and from historical results include, but are not limited to...fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses.

The current ECAC mechanism is a strength in HECO's business risk profile and contributes to HELCO and HECO's financial integrity. The monthly adjustment of the existing ECAC also minimizes the recovery time period, further reducing investor uncertainty with respect to recovery of fuel costs. HELCO ST-18 at 6.

e. Minimizing, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs

The fifth requirement of Act 162 is to "[m]inimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

The ECAC helps minimize regulatory costs and meet this condition. In general, FACs are designed to reduce regulatory costs by separating the volatile fuel costs from the base rates. A prime motivation for FACs is a reduction in base rate cases. The reduction of frequent base rate cases does not reduce the Commission's oversight of HELCO's fuel and purchased power expenditures. Electricity FACs can allow for recovery of narrowly-defined categories of fossil fuel costs, nuclear fuel costs, purchased power, fuel transportation costs, and hedging costs, among others. HELCO submits calculations supporting the ECAC to the Commission for review on a monthly basis. HELCO ST-23 at 24.

Dr. Makholm stated that to further minimize regulatory costs, regulators can see that any other cost category that meets the three criteria for an automatic rate adjustment discussed in the background section receive parallel treatment to those costs already included in the ECAC. Cost categories to consider tracking separately include the following:

(1) All fuel and purchased power costs,

(2) Purchased capacity (especially considering the discussion of renewables),

(3) Hedging costs,

(4) Environmental compliance costs, and

(5) Any other costs specific to the jurisdiction that meet the three criteria discussed earlier. HELCO ST-23 at 24-25.

The ECAC or a similar adjustment mechanism can be implemented efficiently for other costs that are large, volatile and beyond the control of the utility. Also, adjustment and cost tracking mechanisms may be implemented to allow for the parallel treatment of similar costs categories. For example, demand-side management ("DSM") costs provide a substitute for pursuing supply-side resources. If supply-side resources are recovered under an FAC, DSM costs could be treated symmetrically, which would treat supply- and demand-side energy costs on an equal footing. HELCO ST-23 at 25.

Implementing a fuel price hedging program would affect the frequency of HELCO's base rate cases. Currently, the ECAC does not recover hedging costs. If HELCO implemented a hedging program without the ability to recover hedging costs through the ECAC or a comparable rate adjustment mechanism, there would be a potential increase in the need to file expensive base rate cases. Hedging costs, because they are directly tied to fuel and purchased power costs, fit the three criteria established in Section II for an "automatic" rate adjustment. Costs that are large, volatile and generally beyond the utility's control can dramatically impact a utility's financial performance and may prevent a utility from earning its allowed ROE. HELCO ST-23 at 25.

In addition, Dr. Makholm pointed out that the ECAC helps minimize regulatory costs in other ways. Uniformity across the Hawaiian Electric utilities reduces the administrative and transaction costs associated with using an FAC to recover fuel and purchased power costs. Treating HELCO's ECAC separately from HECO's and MECO's ECACs would require further and unnecessary utility and Commission resources devoted to the treatment of fuel and purchased power costs. Additionally, in HELCO ST-24, Mr. Meehan described the potential problems that would arise if HELCO's oil price exposure was hedged separately from its larger affiliates. HELCO ST-23 at 25.

Further, the current ECAC design virtually eliminates fuel price changes as a consideration as to when a rate case is necessary. Any new or modified fuel cost recovery mechanism that is implemented in order to "fairly share the risk of fuel cost changes between the public utility and its customers" and to "preserve, to the extent reasonably possible, the public utility's financial integrity" that results in increasing investors' risks associated with fuel and/or purchased energy would require an increase in investor compensation through a higher cost of capital for bearing the increased risks. Customers would ultimately bear the higher costs for this increase in cost of capital. HELCO ST-18 at 7.

The existing ECAC is a significant rate adjusting mechanism which helps HECO to maintain its current standing with investors. Fuel and purchased power costs are a significant portion of HELCO's expenses and therefore have tremendous potential financial impact. It is essential that the potential creditor and shareholder implications of any change to the ECAC be carefully and thoroughly considered before implementation. HELCO ST-18 at 8.

f. **Consumer Advocate**

The Consumer Advocate agrees that HELCO's ECAC complies with Act 162. As stated by the Consumer Advocate in CA-T-2, page 8, "The Company's proposed ECAC satisfies the requirements of Act 162 considerations." In particular, the Consumer Advocate states that "The Company's ECAC provides a fair sharing of the risks of fuel costs changes between the Company and its ratepayers in a manner that preserves the integrity of the Company without the need for frequent rate filings." CA-T-2 at 64.

In addition, the Consumer Advocate (CA-T-2 at 58) concludes that:

> The ECAC's fixed efficiency factors are thus an effective means of sharing the operating and performance risks between HELCO's ratepayers and shareholders.
>
> With respect to the risk of fuel cost changes due to changes in fuel prices, the ECAC passes such risks in price changes through to ratepayers. Because fuel prices are not within HELCO's control and HELCO is a price taker, it is not considered appropriate for HELCO to bear the risks of fuel cost changes due to price changes established by a global market.

Further, the Consumer Advocate does not support fuel price hedging. Rather, "If the Company cannot achieve non-volatile fuel prices through its fuel purchasing plan, it would seem reasonable that customers who desire less fluctuation in their electric charges from month to month would have the option of levelizing their payments through budget billing that would not charge the customer more than it otherwise would pay over a period of one year." CA-T-2 at 62.

C. <u>EPACT</u>

As defined by the EPACT 2005, a time-based rate schedule is a "schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generating and purchasing electricity at the wholesale level." The federal standard lists three types of time-based rate schedules that may be offered, among others:

1. Time-of-use ("TOU") pricing whereby electricity prices are set for a specific time

period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

2. Critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption.

3. Real-time pricing whereby electricity prices are set for a specific time period on an advance or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly.

The fourth definition in the federal standards is credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations. This is more of a load management concept, than a time-based rate schedule.

EPACT 2005 requires that each State regulatory authority conduct an investigation and issue a decision as to whether it is appropriate to implement the following standards:

1. Each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

2. Each electric utility shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate.

Time-based rates, if designed properly, are intended to provide price signals to consumers on the time-based rate schedule, so they can make decisions on when or whether to use electricity. With this pricing information, the consumer can then choose between consuming electricity now or deferring consumption to another, less costly, time period. Intended benefits of time-based rates may include reduced peak load demand, reduced total demand, increased reliability, more efficient use of current capacity, and lower consumer bills. For example, resulting reductions in peak demand may permit more expensive generators to run less often, and may also reduce the need for the addition of peaking capacity. Deferring consumption also can improve reliability by reducing the load on existing generators and purchased power providers. These benefits are only realized, however, if consumers significantly reduce their demand in response to price signals. Also, analysis and/or market tests may be used to determine if these benefits can be attained in a more cost effective manner using alternative means. HELCO ST-22 at 6-7.

If the rate design proposals in this proceeding are approved by the Commission, HELCO generally would comply with the first standard. HELCO's rate proposals in this proceeding will provide a time-of-use rate schedule for each of its customer classes (except for Schedule F - Street Light Service customers, which do not have significant flexibility to shift load). Should all of the proposed voluntary time-based rates be approved, the portfolio of time-of-use rates will include:

	Time-Based Rate	Applicable Customer Class
1)	TOU-R, Residential Time-of-Use Service	Schedules R & E

2)	TOU-G, Small Commercial Time-of-Use Service	Schedules G, H
3)	TOU-J, Commercial Time-of-Use Service	Schedules J, K
4)	TOU-P, Large Power Time-of-Use Service	Schedule P
5)	Rider M, Off-Peak and Curtailable Service	Schedules J, P

HELCO ST-22 at 7-8.

HELCO proposes to manage participation in these optional rates while collecting data for future time-of-use rate design offerings by setting a limit on the number of meters that can participate in each optional rate schedule. The meter limit facilitates effective implementation of these rate options since the current billing system cannot bill time-of-use rates automatically, and the Company may not have a new Customer Information System (CIS) in place by the time these proposed rates are approved. In addition, the Company has not estimated any revenue adjustment for customer participation in these time-of-use rate options, so the meter limit helps to mitigate any negative revenue impact that the Company might experience in implementing these rate options. HELCO offers a time-of-day Rider T option but is proposing to close it to new customers in lieu of the new time-of-use rates it is proposing in this proceeding. HELCO ST-22 at 8.

In addition, in order to enable the customer to manage his energy use, each customer on a TOU rate schedule will be provided with a time-of-use meter so that the appropriate period pricing can be accurately billed on a monthly basis. HELCO ST-22 at 8.

HELCO is investigating new metering technology. Even though HELCO proposes to implement time-of-use rate options with existing metering technology, its affiliate company, HECO, continues to proactively investigate Advanced Metering Infrastructure ("AMI") solutions. For example, in October 2006, HECO agreed to partner with Sensus Metering

Systems to field test the FlexNet system, which is a full two-way fixed network AMI system that delivers interval meter data. The FlexNet system can facilitate time-of-use pricing options, as well as transmit meter status information. This pilot program will include approximately 500 Sensus "smart" meters in the Honolulu area. HELCO may benefit from the work being pursued by HECO, should AMI prove to be appropriate for metering purposes. HELCO ST-22 at 8.

HELCO currently complies with the second standard. For each participant in its existing or proposed time-of-use rate options, HELCO provides or will provide a time-of-use meter to record and properly reflect period pricing. HELCO ST-22 at 8.

HELCO offers other rate options that take into account the time at which energy is used by the customer. For example, Rider M is an optional off-peak and curtailable service applicable to Schedule J customers with loads greater than 100 kW, and to customers served under Schedule P, with loads greater than 300 kW. Rider M provides load management incentives to customers by modifying the determination of the billing demand under Schedule J or Schedule P. It offers two load management service options: Option A – Off-Peak Service, and Option B – Curtailable Service. HELCO ST-22 at 9.

HELCO plans to offer other types of time-based option. HELCO has included a commercial and industrial load management program in its IRP-3 draft preferred plan, which would provide credits for customers with large loads who enter into pre-established peak load reduction agreements. Under the proposed load management programs, HELCO would pay incentives to customers (which can be a credit to the customers' bills) who install a load control receiver on selected customer loads. In the execution of its five-year IRP Action Plan to be filed with the Commission HELCO will re-evaluate the cost-effectiveness of the load management programs before deciding on the size of any such programs and the scheduling of their implementation. HELCO ST-22 at 9.

With respect to critical peak pricing and real-time pricing, the other two examples of time-based rates included in EPACT 2005, it should be kept in mind that each type of time-based rate is different and may not work the same for all consumer sectors. Most of the benefits of time-based rates will be realized only if consumers respond to price signals and can and do change their consumption patterns. As a result, it is important to understand what types of consumers are present in the market. If load is made up of consumers that are willing and able to adjust their load, then there is more potential than with unresponsive load. This means that sector composition (percent residential vs. percent commercial vs. percent industrial, etc), the willingness of each sector to accept price risk, and the level of risk they are willing to accept, will determine the price responsiveness overall. Residential consumers may have a preference for lower risk. Large commercial and industrial consumers may be more responsive to dynamic prices. Large industrial consumers, which are not generally present on the HELCO system, may have more options to curtail load and may also have the benefit of on-site generation. Thus, time-based rates may only be appropriate for certain consumer sectors or utilities in some locations and the end decision may be that time-based rates are appropriate for some sectors or utilities but not for others. HELCO ST-22 at 9-10.

HELCO understands that critical peak pricing and real-time pricing rate levels on the mainland are based, in part, on market prices for electricity. However, because HELCO lacks access to a wholesale market (i.e., HELCO operates a stand alone system on the island of Hawaii), a pricing signal to drive critical peak pricing and real-time pricing is not available to the Company. Thus, it is unclear at what levels HELCO's critical peak pricing or real-time pricing rates would be set. In addition, HELCO has proposed time-of-use rates for its customer classes in this rate proceeding and believes that it would be prudent to evaluate its customers' response to those rates before moving to rates that are more complicated for customers to understand. Therefore, the Company is not proposing critical peak and real-time pricing at this time. HELCO ST-22 at 10.

With respect to the time-based metering and communications standards included in the Energy Policy Act of 2005, the Commission's adoption of the standards articulated the Energy Policy Act of 2005 is not necessary because:

1. The Company will comply with the standard regarding the offer of time-based rates once the proposed rate design is approved.

2. HELCO's affiliate company, HECO, is already proactively investigating advanced metering and telecommunications infrastructure (AMI) solutions that will enhance the ability of the consumer to manage his energy use and cost. These solutions may prove to be beneficial to HELCO as well. HELCO ST-22 at 10-11.

The fact that HELCO generally is in compliance with the standard does not mean that the Commission should adopt the standard. First, as stated above, adoption of the standard is unnecessary. In addition, adoption of the standard could have unintended consequences. For example, the standard could be construed to require that street light customers be offered a time-of-use option, or that there be no initial limit on the number of meters that can initially participate. HELCO ST-22 at 11.

In general, one size fits all federal standards are not the optimal method to achieve objectives such as equitable rates for electricity consumers. The purpose underlying PURPA can be met without adopting the time-based metering and communications standards. The stated purposes of the PURPA Title I standards, as enunciated in 1978, are to encourage (1) conservation of energy supplied by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates for electric consumers. The Conference Committee Report that accompanied the passage of PURPA in 1978 explained further that the first purpose of the Title was to foster conservation by end-users of electricity. The second purpose was directed at utilities and their use of energy and their facilities, including capital resources, and intended this to include "conserving scarce energy resources by techniques of rate reform which substitute the use of more plentiful resources produced in the United States in lieu of less plentiful resources, especially those imported into this Country." Joint Explanatory Statement of the Committee of Conference, Conference Committee Report accompanying Public Law 95-61 7 (PURPA), 1978, p. 69. Nothing further was added to the third purpose beyond what was said in the statute, that is, that it was intended to encourage equitable rates for consumers. This standard is closely tied to the first two stated purposes of PURPA, to (1) encourage conservation of energy supplied by electric utilities and (2) optimize the efficiency of electric utility facilities and resources. HELCO ST-22 at 11-12.

PURPA did not take the primary responsibility over electric utility rates from the states. The Title I standards impose certain obligations on state regulatory commissions and give certain rights to persons to go before state regulatory commissions and state courts. However, under PURPA and its amendments, states retain primary responsibility with respect to retail electric rates. PURPA and the three purposes are intended to supplement state law, but do not override state law. Conference Committee Report, pp. 70-71. Also, states may consider other purposes as well that are not specified by PURPA. State commissions are not required to take actions that conflict with state law. The intention was to preserve the discretion of state commissions that is provided by state law - except to the extent that Title I imposes procedural requirements, such as requirements to hold hearings and consider and make a determination. HELCO ST-22 at 12 (citing Conference Committee Report, page 71).

Section 269-16 of the Hawaii Revised Statutes ("HRS") not only encourages equitable rates for consumers. It requires rates to be just and reasonable and prohibits unreasonable discrimination between localities, or between users or consumers, under substantially similar conditions. HRS 269-16 and Chapter 6-61 of the Hawaii Administrative Rules prescribe procedures to consider utility rate proposals and to determine whether the proposed rates are just, reasonable and non-discriminatory. It is in this ratemaking process that the underlying purpose of PURPA to encourage equitable rates for consumers is met. Since such a process already exists, it is not necessary for the Commission to adopt the federal standards to encourage equitable rates for consumers. Rather, rates should be established based on the specific needs and circumstances that currently exist on this island. HELCO ST-22 at 13.

The Commission has previously considered whether to adopt Energy Policy Act standards. In Docket No. 94-0203, by Order No. 13387, filed July 19, 1994, the Commission instituted a proceeding to consider and determine the appropriateness of implementing the energy efficiency standards established by the Energy Policy Act of 1992 for electric utilities under PURPA Section 111. By Decision and Order No. 14454, filed January 12, 1996, the Commission concluded that it need not adopt the federal standards in order to be in compliance with Section 111 of PURPA, as amended by the Energy Policy Act of 1992. HELCO ST-22 at 13.

V. CONCLUSION

Based on the foregoing, and the entire record herein, HELCO respectfully requests that the Commission approve the total increase in revenues, and the revised rate schedules requested by HELCO.

DATED: Honolulu, Hawaii, June 4, 2007.

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CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing **OPENING BRIEF OF HAWAII ELECTRIC LIGHT COMPANY, INC.**, together with this Certificate of Service, by hand delivery and/or by mailing a copy by United States mail, postage prepaid, to the following:

Division Of Consumer Advocacy
Department of Commerce & Consumer Affairs
335 Merchant Street, Room 326
Honolulu, HI 96813

Keahole Defense Coalition, Inc.
c/o Keiichi Ikeda
P.O. Box 5618
Kailua-Kona, Hawaii 96745

DATED: Honolulu, Hawaii, June 4, 2007.

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